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Final Report

ELECTRIC FINANCIAL FEASIBILITY STUDY

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January 16, 2004

Via FedEx

Ms. Gloria L. Young
Executive Officer
Local Agency Formation Commission
1 Dr. Carlton B. Goodlett Place, Room 244
San Francisco, California 94102-4689

Subject: **Electric Financial Feasibility Study**

Dear Ms. Young:

Enclosed are 25 copies (11 comb-bound and 14 stapled) of R. W. Beck, Inc.'s Final Report of the Electric Financial Feasibility Study for the City and County of San Francisco.

Sincerely,

R. W. BECK, INC.

Kenneth J. Mellor, PE
Senior Director of Consulting

KJM:jm
Encl.

c: Mike Bell
Legal Dept (2)

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San Francisco Local Agency Formation Commission
ELECTRIC FINANCIAL FEASIBILITY STUDY

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This report has been prepared for the use of the client for the specific purposes identified in the report. The conclusions, observations and recommendations contained herein attributed to R. W. Beck, Inc. (R. W. Beck) constitute the opinions of R. W. Beck. To the extent that statements, information and opinions provided by the client or others have been used in the preparation of this report, R. W. Beck has relied upon the same to be accurate, and for which no assurances are intended and no representations or warranties are made. R. W. Beck makes no certification and gives no assurances except as explicitly set forth in this report.

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Final Report

ELECTRIC FINANCIAL FEASIBILITY STUDY

San Francisco Local Agency Formation Commission

January 2004

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Background

The San Francisco Local Agency Formation Commission (SF LAFCO) engaged R. W. Beck, Inc. (R. W. Beck) to provide an independent analysis of full municipal ownership of the electric utility in the City and County of San Francisco (San Francisco). This analysis is the third in a series of evaluations considering different electric energy alternatives. The first two studies addressed:

1. Electric service needs and options to increase reliability, efficiency, and cost-effectiveness in San Francisco.
2. Community Aggregation, as authorized by Assembly Bill 117 (AB 117).

As the result of the first two studies, it was determined that San Francisco has a competition advantage for the supply of electricity because of its ownership of Hetch Hetchy Water and Power (Hetch Hetchy or HHWP); broad public support for renewable resources, conservation and efficiency; and strong local involvement. The key issue for this third evaluation is whether the electric transmission and distribution systems currently owned by the Pacific Gas and Electric Company (PG&E) in San Francisco could be acquired and severed from the balance of the PG&E system at a cost that would provide long-term economic savings to electricity customers in San Francisco.

In order to address the question of the viability of full municipalization in San Francisco, information was obtained from PG&E regarding historic customer class loads and revenues. Estimates were developed by R. W. Beck regarding the condition and value of the PG&E facilities to be acquired, costs of severance, and costs of system Operation and Maintenance (O&M). An integrated financial model was developed to facilitate the analysis of projected operating results under a range of critical assumptions.

A first draft of this report was prepared and distributed to interested stakeholders in September 2003. Several public hearings were held to provide for public input on the initial assumptions and conclusions. PG&E provided load and revenue data during the process that had not been available during the initial analysis. To the extent appropriate (governed by the scope of the assignment), public input and new data was integrated into the final report and conclusions were modified to reflect the new information. The conclusions follow.

Conclusions

We have reached the follow general conclusions based on R. W. Beck's analysis of information provided by various sources, including San Francisco, the San Francisco

Public Utilities Commission (SFPUC), the Department of Environment, the California Public Utilities Commission (CPUC), the California Energy Commission (CEC), the California Power and Conservation Financing Authority, the California Independent System Operation (CAISO), PG&E, and other sources:

Based solely on the economic analysis and the scenario analysis in Section 3 of this report, it would appear that it is in the City's best long-term interest to continue to pursue the acquisition of transmission and distribution facilities within San Francisco. Under most cases, even with conservative assumptions, it would appear that over the long term, savings could be achieved for the San Francisco ratepayer. Base Case scenario Net Present Value (NPV) savings range from $0.75 billion to $1.47 billion, depending on assumptions regarding the cost of the distribution system and severance from PG&E.

Table ES-1
Base Case Results

	Base Case		
	Low Value	**Mid Value**	**High Value**
Distribution System Cost	720,000,000	1,120,000,000	1,520,000,000
Severance Cost	1,966,000	3,818,000	42,759,000
20-year NPV ($000)	1,469,178	1,125,318	749,721
Average Retail Rate	0.1369	0.1369	0.1369
Average Break-Even Rate	0.1124	0.1182	0.1246

The technical assessment raises some concerns that should be considered and discussed before a decision is made with regard to acquisition of existing facilities in San Francisco. The age and condition of the system present challenges and risks to the City that could make its acquisition undesirable. A large portion of the residential and strip commercial areas of the City are served by a 4-kV system that is becoming obsolete. The network system serving the central business section of the City, although highly reliable, is expensive to maintain. Substantial improvements will need to be made to large sections of the distribution system in the years to come. If the cost of acquiring the system is on the high end of the estimate and the City ultimately has to abandon or overbuild significant portions of the system, it might not be worth the cost of acquisition.

The Table ES-1 outlines our perceived major benefits and risks for San Francisco, should it proceed with the acquisition of PG&E's transmission and distribution facilities.

Table ES-2
Electric System Acquisition

Benefits	Risks
■ Economic analysis indicates likelihood of ratepayer savings over the long term.	■ Age and condition of system.
■ City-owned resources could provide further savings.	■ Protracted fight with PG&E.
■ Greater control over investment/reliability.	■ Variability of costs, revenues, and market prices.

The economic analysis indicates that NPV savings could be achieved under most scenarios. In addition, the integration of City-owned resources provides both a hedge to higher prices and less reliance on market purchases. Integration of these resources into the plan would tend to improve the economics over time. Finally, the City could exert greater influence and control over investment and reliability decisions through acquisition.

There are three significant risks associated with acquisition. The first is the age and condition of the system. The City would need to be very careful not to pay significantly more than the system is worth, and must also be prepared to invest in the improvement and upgrade of the system. Much of the distribution system in San Francisco is 4-kV circa 1950s. In addition, the downtown network system is complex and costly to maintain.

The second major risk is the reaction from PG&E to an attempt to acquire existing facilities. The City can expect PG&E to contest the acquisition of existing facilities with fierce opposition and considerable legal and political resources. The City must be prepared to deal with these issues if the acquisition stands a chance of succeeding. Historically, very few communities have been able to withstand this kind of intense opposition.

Finally, the City would need a sound management plan to deal with the major risks of owning and operating an electric delivery system and supplying retail load. The sensitivity analysis determined that realistic changes in load, market prices, retail rates, and potential changes in other costs could eliminate identified savings.

Recommendations

Based on the technical assessment, economic analysis, and risk management considerations, R. W. Beck submits the following recommendations for SF LAFCO's consideration.

1. Proceed with acquisition alternative – a detailed appraisal.
2. Evaluate cost-benefit of facilities' acquisition during detailed valuation process. Some sections of the system may be less costly to replace than to acquire.

3. Power supply options can be pursued immediately through implementation of AB 117 and later integrated if the acquisition of other facilities occurs.

4. Develop a sound management plan to deal with the major risks of owning and operating an electric delivery system and supplying retail load.

Given the outcome of the economic analysis, further detailed consideration of transmission and distribution system acquisition appears warranted. This can be achieved through a thorough evaluation and appraisal of the existing facilities. Care should be taken in order to determine, as a result of this process, which facilities are salvageable, at what reasonable cost, and what facilities need to be replaced in their entirety. Such a complete system appraisal is likely to take six months to perform from start to finish and is estimated to cost approximately $500,000 to $600,000.

Regardless of what happens with Recommendations 1. and 2. above, the findings of this analysis further support and reinforce the earlier studies that determined that implementation of AB 117 is in the best interest of San Francisco.

Finally, the City should consider the political and legal consequences of pursuing these actions. The process of acquiring facilities from an unwilling seller with the resources and clout of PG&E would most likely be time consuming and costly.

R. W. Beck would like to thank the Executive Director of SF LAFCO, Gloria Young; Nancy Miller of Hyde, Miller and Trost; and Pat Martel, Ed Smeloff, Merle Jurosek, and the staff at the SFPUC for their contributions to this report.

Section 1

BACKGROUND AND KEY ASSUMPTIONS

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Background

This Electric Financial Feasibility Study (Study) is the third in a series of investigations by SF LAFCO to assess the provision of electric utility service in San Francisco.

First Study

The first study addressed electric service needs and various options that were available to increase service reliability, efficiency, and cost effectiveness. A final report entitled "*Energy Services Study*" was completed in July 2002. The study concluded that San Francisco is "uniquely at risk" due to transmission constraints into the City, the potential for loss of local generation, and uncertainties surrounding the emergence from bankruptcy of PG&E. It was determined that San Francisco had a competitive advantage for the supply of electricity because of its ownership of HHWP; broad public support for renewable resources, conservation and efficiency; and strong local involvement. Options outlined for exploiting these advantages included:

- Ownership or participation in local generation and power supply markets with one or more of the following potential objectives:
  - Increasing local generation
  - Substitution of new generation for existing generation to obtain reduced emissions and enhanced reliability and efficiency
  - Serving retail load
- Ownership or participation in expanded transmission to:
  - Enhance reliability
  - Offset the need for some local generation
  - Reduce the potential for congestion price effects on retail rates
- Provide energy-related retail services via:
  - Aggregation as a Facilitator
  - Aggregation as an Energy Services Provider
  - Community Aggregation
- Provide integrated retail electricity services, such as:
  - Full municipalization of the distribution system

- Spot municipalization
- Services to loads adjacent to SFPUC facilities

- Increase efforts in conservation, energy efficiency, renewable, and distributed generation.

Second Study

The second study focused on the potential for Community Choice Aggregation under provisions of AB 117 legislation that became law in 2002. A final report entitled *"AB 117 Assessment Report for the City and County of San Francisco"* was completed in August 2003. The report included the following conclusions:

- Under conservative assumptions, annual estimated savings due to Community Aggregation in San Francisco are likely to be between $10 and $35 million annually (5-20%). Actual savings will be dependent on a number of critical factors, including:
  - whether the generating credit given by PG&E to Direct Access customers is approximately equal to that to be provided for Community Aggregation, as assumed in the analysis;
  - other non-bypassable charges that might be imposed by the CPUC;
  - the outcome of the PG&E bankruptcy;
  - wholesale electricity market prices; and
  - natural gas prices.
- If San Francisco can integrate surplus Hetch Hetchy resources and the newly acquired Williams Companies' combustion turbines into the power supply portfolio, savings should increase. Analyses will need to consider the loss of revenues to the City from any sales of these resources into the wholesale electricity markets.
- The San Francisco load profile should be less costly to serve than the PG&E system load profile. Preliminary analyses indicated a small cost advantage based on a combination of non-detailed load profile data and market price information that was not robust or was affected by dysfunctional electricity markets. More complete data from PG&E for the San Francisco service area, including current data by customer segment, will be required to confirm these results.
- The CPUC has been slow to address implementation plans and cost responsibilities for Community Aggregation. However, the City is in a good position to work with the CPUC to obtain consideration of its needs as CPUC rules are evaluated and adopted. If San Francisco is interested in pursuing Community Aggregation, it is important to be active in this process.
- Analysis of the advantages and disadvantages of the various potential governance structures cause us to recommend that the SFPUC is the most logical choice to lead further investigation into a Community Aggregation Plan.

- There are a number of factors that will undoubtedly change a final analysis of Community Aggregation, including the determination of non-bypassable charges by the CPUC; site-specific San Francisco load data that PG&E will be required to provide; the outcome of the PG&E bankruptcy; and the ground rules for future pricing decisions either through a market or regulated return basis. In any case, it appears that the potential benefits of Community Aggregation warrant SF LAFCo's consideration of Community Aggregation and that the SFPUC would be the appropriate agency to undertake the tracking of CPUC rulemaking and related analyses.
- If the San Francisco Board of Supervisors ultimately elects to implement Community Aggregation and authorizes the preparation by San Francisco of an Implementation Plan to be filed at the CPUC, we estimate that it would take approximately four to six months to complete the plan and another four to six months to receive CPUC authorization once the plan is filed. Therefore, it is unlikely that Community Aggregation could be implemented much before 2005. An outline of the steps needed to implement Community Aggregation is contained in Section 5 of the second study, and considerable discussion of the work that would need to be done is included in all sections of that report.

Third Study

This third Study includes a technical assessment of San Francisco becoming a full-service municipal electric utility, an economic analysis, a risk assessment, and conclusions and recommendations.

Key Assumptions

There are several fundamental assumptions that were included in the scope of this Study:

- That San Francisco would be a fully integrated electric utility. That means that it would be responsible to arrange for the supply of all electric loads and provide reliable transmission and distribution services within San Francisco.
- San Francisco would use its own existing infrastructure to minimize the acquisition of PG&E properties, such as PG&E office buildings and the Martin Substation.
- In order to minimize severance costs and to enhance control of local generation, the Hunter's Point Power Plant would be included in the acquisition.
- The data provided to the City by PG&E regarding customer class loads and load profiles was accurate. (Note: Data for the first draft report came from the 2002 hourly load profile provided by PG&E, while data for the final draft came from energy and demand consumption by rate class provided by PG&E.)

- PG&E rates will be adjusted according to the CPUC Final Decision in the PG&E bankruptcy case and that PG&E is successful at the California Legislature in getting a dedicated rate component to refinance the regulatory asset created by the bankruptcy settlement. PG&E rates are assumed to be a reasonable benchmark to evaluate the economics of fully integrated service from San Francisco.
- It was assumed that transmission within San Francisco would be acquired along with the distribution system because of the fact that those systems often share facilities, including substations, poles, and vaults. A full engineering study would be required to determine the optimum purchase of transmission facilities and it would be necessary to consider facility costs, severance costs, changes in ongoing transmission charges by PG&E and the CAISO, and the outcome of Federal Energy Regulatory Commission (FERC) regulation regarding Locational Marginal Pricing.

Section 2

TECHNICAL ASSESSMENT

TECHNICAL ASSESSMENT

The Technical Assessment section includes the development of an estimate of acquisition costs, severance cost, and costs of operation of a vertically integrated municipal utility in San Francisco. Vertical integration assumes that San Francisco is responsible for the provision of power supply, transmission, and distribution services in whole or in part within San Francisco.

Power Supply

The power supply cost scenario contained in the first draft of this report conservatively assumed that San Francisco obtained its supply entirely from the market. These costs would be lower if Hetch Hetchy power is melded with market power, particularly if the addition of new loads served by a municipal utility allowed increased use of Hetch Hetchy power pursuant to The Raker Act. Power supply costs were estimated using load data obtained from PG&E through San Francisco. Load growth used in the first draft of this report was based on the peak load projections provided in the publication titled "The Electricity Resource Plan, Choosing San Francisco's Energy Future," prepared by the collaborative efforts of the SFPUC and the San Francisco Department of Energy (SF DOE) dated December 2002. Additional sensitivities were run using more conservative load growth estimates. The results of these runs are included in Section 3 and **Appendix A** of this report. Loads for San Francisco by customer class are shown below in Table 2-1 and were provided by PG&E.

Table 2-1
San Francisco Loads by Customer Class

	Residential	Commercial/Industrial			Municipal	Total SF Load
		Small	Medium	Large		
2002	1,336,077	527,393	1,462,059	1,138,644	609,130	5,073,304
2003	1,362,799	537,941	1,491,301	1,161,417	609,130	5,162,587
2004	1,390,055	548,699	1,521,127	1,184,646	621,313	5,265,839
2005	1,417,856	559,673	1,551,549	1,208,338	633,739	5,371,156
2006	1,439,124	568,069	1,574,822	1,226,464	643,245	5,451,723
2007	1,453,515	573,749	1,590,571	1,238,728	649,677	5,506,240
2008	1,468,050	579,487	1,606,476	1,251,115	656,174	5,561,303
2009	1,482,730	585,282	1,622,541	1,263,627	662,736	5,616,916
2010	1,497,558	591,134	1,638,766	1,276,263	669,363	5,673,085
2011	1,512,533	597,046	1,655,154	1,289,026	676,057	5,729,816
2012	1,527,659	603,016	1,671,706	1,301,916	682,817	5,787,114
2013	1,542,935	609,046	1,688,423	1,314,935	689,646	5,844,985
2014	1,558,365	615,137	1,705,307	1,328,084	696,542	5,903,435
2015	1,573,948	621,288	1,722,360	1,341,365	703,508	5,962,469
2016	1,589,688	627,501	1,739,584	1,354,779	710,543	6,022,094
2017	1,605,585	633,776	1,756,979	1,368,327	717,648	6,082,315
2018	1,621,640	640,114	1,774,549	1,382,010	724,824	6,143,138
2019	1,637,857	646,515	1,792,295	1,395,830	732,073	6,204,569
2020	1,654,235	652,980	1,810,218	1,409,788	739,393	6,266,615
2021	1,670,778	659,510	1,828,320	1,423,886	746,787	6,329,281
2022	1,687,486	666,105	1,846,603	1,438,125	754,255	6,392,574

The cost of energy associated with serving this load is taken from the CEC's Electricity Infrastructure Assessment study issued in May 2003. The CEC's forecast of future energy prices are shown below in Table 2-2.

Table 2-2
Market Price Projections

Year	Market Price ($/MWh)	Year	Market Price ($/MWh)
2003	30.00	2014	52.00
2004	34.67	2015	53.35
2005	32.27	2016	54.74
2006	34.02	2017	56.16
2007	37.08	2018	57.62
2008	39.62	2019	59.12
2009	41.40	2020	60.66
2010	43.81	2021	62.24
2011	45.69	2022	63.86
2012	48.36	2023	65.52
2013	50.68		

These market prices represent the CEC's estimates of annual average power supply costs. Since these projections were developed, natural gas prices have increased dramatically, and because gas prices drive electricity market prices, market prices have increased accordingly. In the long term, PG&E rates will have to reflect changes, whether up or down, in electricity prices for that part of their resource mix that is tied to gas prices. Therefore, to the extent that market prices shown in Table 2-2 are above or below actual future prices, PG&E rates would be expected to track (by 60% to 65%) such changes. This reflects the fact that PG&E's nuclear and hydroelectric resources are not linked to natural gas or electricity market prices.

Facilities Valuation

Introduction

A large portion of the cost associated with any municipalization effort is related to the acquisition of the property by the start-up municipal organization. This section of the report provides an estimate of the value of PG&E's electric system that would be acquired by the City.

The valuation analysis was performed using publicly available information and data that was provided by the City. These sources include the following:

- PG&E's 2002 FERC Form 1 Annual Report
- Load data for San Francisco (MWh sales and customers) that the City obtained from PG&E.
- Energy Services Study prepared for SF LAFCO dated July 2002.
- The Handy-Whitman Index of Public Utility Construction Costs

- The Gas Turbine World Handbook

R. W. Beck also conducted a limited field review of the system to determine the type of construction, age and condition of the electric system, and to evaluate potential severance issues. The field review was limited to above ground facilities that could be observed from the street. In order to obtain information on underground facilities, PG&E would need to provide maps and detailed information on dates of installation, construction standards in use at the time, and maintenance and replacement records.

Our analysis provides a reasonable basis for the purpose of this Study for estimating the range of potential purchase prices the City might have to pay PG&E to acquire the electric system. The valuation methodologies used are described in the following paragraphs. If the City decides to proceed with municipalization, we recommend that a detailed appraisal be performed to determine the estimated fair market value of the system.

Facilities Valued

Following is a description of the San Francisco electric system facilities included in the valuation analysis:

- Transmission lines consisting of five 115-kV and two 230-kV circuits, all of which originate at PG&E's Martin Substation and extend north to substations located in the City.
- All substations located within the City:
    - Potrero (115/12 kV)
    - Hunter's Point (115/12 kV)
    - Bayshore (115/35 kV)
    - Mission (115/12 kV)
    - Larkin (115/12 kV)
    - Embarcadero (230/35 kV)
- Distribution lines, the majority of which are overhead 4-kV, with some overhead 12-kV lines, and an underground distribution network in the core downtown area.
- Generation facilities at Hunter's Point, which consist of Hunter's Point #1, a 52-MW oil-fired combustion turbine that went into service in 1976, and Hunter's Point #4, a 163-MW natural gas-fired steam generation plant that went into service in 1958.

A more detailed description of the San Francisco electric system can be found in the severance analysis contained later in this section of the report.

Value of Transmission and Distribution Facilities

Two indicators of value that are commonly considered when valuing electric transmission and distribution facilities are the Original Cost Less Depreciation (OCLD) value and the Reproduction Cost New Less Depreciation (RCNLD) value of

the property. OCLD is defined as the original cost of the property when it was first put into service, less accrued depreciation. The OCLD value is equal to the net book value of the property, which is generally equivalent to the rate base value of the property for ratemaking purposes. RCNLD is defined as the cost of constructing an exact replica of the property at current prices with the same or closely related materials, less accrued depreciation. The RCNLD and OCLD values tend to set the upper and lower limits, respectively, on the range of fair market value for electric transmission and distribution facilities.

Plant in-service (or original cost) data for the total PG&E electric transmission and distribution system were obtained from PG&E's FERC Form 1 Annual Report. To estimate the OCLD value of the transmission and distribution facilities located within the City, we allocated the total PG&E transmission and distribution net plant in-service as of December 31, 2002, using two different ratios:

- the ratio of PG&E energy sales in the City to total system energy sales and
- the ratio of PG&E electric customers in the City to total PG&E electric customers.

The City represents approximately 7% of the total PG&E system based on relative MWh sales and customers.

From the FERC Form 1 data, we also obtained the total amount of accumulated depreciation and depreciation expense for the PG&E transmission and distribution plant. The average age of the system was estimated by dividing the accumulated depreciation by the annual depreciation expense. The resulting average installation year for PG&E's transmission and distribution system is 1987. Based on this average installation year, the RCNLD value was then estimated by trending the OCLD value to the current cost using the Handy-Whitman Index of Public Utility Construction Costs, a semi-annual publication used widely in the electric industry.

The analysis discussed above assumes that the transmission and distribution facilities in the City are comparable to the system average. However, as observed during our field review, much of the above ground distribution system in the City is an old, 4-kV system that is much older than the system average age of PG&E's transmission and distribution plant, and is near the end of its useful life from both a physical and technological standpoint. On the other hand, many of the transmission lines in the City are underground, which are more expensive to build than overhead transmission lines that are more typical of the system average. The downtown underground network in the City would also have a higher cost than the average overhead distribution system. This network system is also expected to include a large percentage of cable, transformers, network protectors, and other components that are older than the average age of the PG&E system. Other parts of the underground distribution system in San Francisco are likely to be closer to the average age of the PG&E system. We considered the age, condition, and type of construction of the San Francisco system, but relied more on the results of the system average analyses in developing our estimates of value for the purpose of this Study. A more detailed appraisal of the system would take into account all factors affecting value.

It is our experience, based on past sales and acquisitions of property involving PG&E, that PG&E typically estimates the value of utility property it is selling based on the RCNLD value using the present worth (or sinking fund) method of depreciation, as opposed to the straight-line method of depreciation. The effect of using the present worth method of depreciation is to understate the reserve for accumulated depreciation and thus overstate the value of net plant compared to the straight-line method of depreciation. Calculating a value for the system based on the RCNLD value using the present worth method of depreciation increases the likelihood that PG&E will be successful in getting a higher purchase price through negotiation or court award. In other words, the RCNLD (straight-line depreciation) value becomes the mid-point in the range between the OCLD and RCNLD (present worth depreciation) values.

Value of Generation Plant

The discussion thus far has focused on the value of PG&E's electric transmission and distribution facilities in the City. A different approach was used to estimate the value of the Hunter's Point that is owned and operated by PG&E. (The Potrero Power Plant, although located in the City, is not owned by PG&E and is not included in the valuation analysis). The value of the Hunter's Point Power Plant was estimated using the replacement cost method. The replacement cost method involves determining the estimated current cost of facilities that could be designed and constructed under present market conditions to produce an equivalent net functionality to that of the property being valued. For generating plant, where technology has resulted in a significant shift in the way energy is produced (e.g., coal-fired generation is currently being replaced by natural gas-fired, combined-cycle generation), the replacement cost method is the preferred method for estimating value under the cost approach.

For Hunter's Point #1, the replacement unit was assumed to be a 50-MW simple-cycle, gas combustion turbine and for Hunter's Point #4, the replacement unit was assumed to be a 160-MW gas-fired, combined-cycle plant. Using data from the Gas Turbine World Handbook, we estimated the current installed cost for each of the replacement units. Although the Hunter's Point Power Plant is old and close to retirement, Units #1 and #4 continue to be operated and, therefore, have some value.[1] For the purpose of this valuation analysis, we assumed that 10% of the value in Units #1 and #4 still remains, i.e., the units are 90% depreciated. We have not taken into consideration the cost to dismantle the power plant after it is retired. If the City proceeds with acquisition, the cost of dismantling Hunter's Point should be further evaluated. The estimated value of the generation plant was added to the indicators of value developed for the transmission and distribution facilities.

It may not be necessary for the City to acquire the generation facilities owned by PG&E within the City. However, control of scarce generation may be important to maintaining reliability and has been included in the valuation. Additionally, acquisition of the Hunter's Point Power Plant could reduce severance costs. Generation comprises only 1.8% of the estimated value of the total distribution,

[1] An agreement signed in 1998 between the City and PG&E calls for the Hunter's Point Power Plant to be retired once the plant is no longer needed to provide electric reliability in San Francisco.

transmission, and generation assets. Whether or not these assets are acquired will have little influence on the financial outcome of the analysis.

Valuation Summary

The analyses described above do not constitute an appraisal of PG&E's electric system in San Francisco. However, for the purpose of this Study, the analyses provide a reasonable basis to estimate a range of value and potential purchase price for the San Francisco electric system. Based on the results of our analyses, we developed low, mid and high estimates of the value of the electric system, as shown in Table 2-3 below:

Table 2-3
Estimated Value of San Francisco Electric System[2]

Low Value	$720,000,000
Mid Value	$1,120,000,000
High Value	$1,520,000,000

These estimates, along with the power supply and severance costs, are used in the economic analysis contained in Section 3 of this report. The methodology used to develop the high-level estimate of values for the transmission and distribution systems did not allow a breakdown into specific components, such as transmission, distribution, and general plant. It should be noted, however, that general plant would typically comprise approximately 1.5% of the total and would include warehouses, yards, and rolling stock. Additionally, on a system wide basis, transmission comprises somewhat less than 20% of PG&E's combined transmission and distribution plant. It is expected that the percentage of transmission plant in San Francisco is lower than the system wide average.

Severance Cost

In addition to the acquisition cost of purchasing the PG&E system within San Francisco, there will be costs associated with creating physical separation and metered interconnections between the two systems.

The cost and complexity of severance can vary greatly. The costs are affected by:

- Technical issues associated with maintaining service reliability, redundancy, and capacity.
- The level of cooperation between utilities.
- The extent of new or duplicate facilities required on one or both sides of the boundary.
- Possible penalties or costs associated with rendering existing facilities under-utilized (stranded costs).

[2] Includes the effect of system purchase costs, acquisition costs, debt reserves, and working capital.

Severance of San Francisco from the PG&E system is greatly simplified by the geography of the peninsula, which forms a natural separation from the greater Bay Area on all sides, except the southern boundary with San Mateo County. This eliminates the onerous technical issues that can occur when a separation creates a "hole" in an existing utility's service area with transmission and distribution lines tracing in to and back out of the boundary.

The severance issues are summarized in this report under the following sections:

- Transmission System Severance
- Distribution System Severance Approaches (Cases 1, 2, and 3)
- System Information and Assumptions
- Severance Cost Estimates

Transmission System Severance

The transmission system feeding into the City consists of five 115-kV and two 230-kV circuits, all of which originate at PG&E's Martin Substation. This system is unique compared to other transmission systems in that, once these seven circuits exit Martin Substation, they serve only substations located within San Francisco. The fact that the transmission circuits all originate at a single substation and do not extend back out of the City provides a rare opportunity for a transmission system severance solution that is unusually clean, straightforward, and relatively low-cost.

The likely transmission severance scenario would be for the City to take ownership of all substations within the City limits and all transmission lines north of PG&E's Martin Substation. Revenue metering would need to be installed at Martin Substation on the five 115-kV and two 230-kV lines that feed the City substations.

Installation of revenue metering at the 115-kV and 230-kV level requires replacement or addition of substation current and voltage transformers, along with meters and communications. This rarely requires substation expansion or major modifications.

Distribution System Severance Approaches

Although the geography of San Francisco greatly reduces the quantity of severance issues in the 12-kV and 4-kV distribution system, as compared to other urban areas, there will still be issues along the southern boundary where San Francisco County meets San Mateo County.

The San Francisco–San Mateo County boundary is defined by a straight-line cut across the peninsula, and streets and neighborhoods do not correspond in any way with the city boundary. The electrical distribution system follows the streets and property parcels and thus crisscrosses the boundary. Every crossing point is a potential severance issue that would need to be resolved. Furthermore, the distribution system on the south side of the City is fed by two substations that are located in San Mateo County. Additional discussion of the system configurations and

substations is included under the subsection entitled "System Information and Assumptions."

The cost of addressing distribution system severance issues in San Francisco depends greatly on the level of cooperation between PG&E and the City. Based on our field review and analysis, we have identified three general approaches to distribution severance. The three approaches are described as Severance Cases 1, 2, and 3 below and correspond to different levels of cooperation between PG&E and the City.

Severance Case 1: Maximum Cooperation with Fringe Agreements

- Neighboring utilities that have cooperative relationships use Fringe Agreements to provide the best system performance at the lowest cost by allowing system configurations to be determined by logical engineering and operating constraints rather than political boundaries. With Fringe Agreements, construction of duplicate facilities is unnecessary.
- Under a Fringe Agreement solution, PG&E would continue to operate the portions of the electrical system on the south edge of the City that are served by the Martin and Daly City Substations, but the billing and customer accounts would be transferred to the City.
- Due to the geographical arrangement of the system and locations of substations, it is unlikely that the City would be serving customers in San Mateo County in a reciprocal manner.
- Under this arrangement, a "virtual" severance is implemented through account management and almost no facilities would need to be constructed.

Severance Case 2: Reasonable Cooperation with Primary Metering

- Primary metering would be installed on the overhead and underground 4-kV and 12-kV distribution feeders where they cross the city boundaries.
- Construction of major new facilities (substations, transmission connections, and main line primary feeders) would be unlikely.
- Some reconfigurations would be involved to reduce the number of interconnection metering points and minimize subtractive metering situations (where power flows into the City through one metering point and then back out of the City through another metering point).

Severance Case 3: Minimal Cooperation with Complete Severance and Isolation

- A hard physical separation would occur at the political boundary of San Francisco and San Mateo Counties. No distribution lines would cross the boundary (some crossings could be retrofitted with isolation switches to allow for emergency situations).
- Next-door neighbors would be served by different electric utilities, depending on how the city boundary split the neighborhood.

- Significant and costly new facilities would need to be constructed within San Francisco, including a major substation and a transmission connection.
- Major construction on the San Mateo (PG&E) side would be unlikely, although there would be some reconfigurations and modifications.
- Significant PG&E facilities would no longer be utilized to full capacity due to the duplicate facilities constructed within the City.
- In an effort to drive up the costs of municipalization, PG&E will most likely refuse to cooperate with the City and argue that this full and complete severance is the only acceptable solution.

System Information and Assumptions

A complete analysis of severance issues requires extensive review of system maps, electrical schematics, and systems data. The scope of this Study was to determine likely scenarios and a range of costs that could be anticipated, but not to perform the comprehensive analysis of severance solutions.

Since data was not available from PG&E, this discussion of severance option scenarios is based on:

- Field observations of substations, transmission system, and distribution lines.
- Physical locations of substations relative to residential neighborhoods and load density.
- Likely existing distribution feeder routing arrangements given geographic constraints (San Bruno Mountain Park, San Francisco Golf Club, etc.).

Quantities assumed in the Severance Costs Estimates are based on:

- Field observations of substation facilities and distribution lines.
- Publicly available substation load and transformer information (FERC Form 1, published system studies, etc.).
- Publicly available GIS databases and maps.

The Transmission System Severance approach and cost estimates assume that revenue metering can be installed at Martin Substation on the seven transmission connections with relative simplicity. The cost estimates do not include substation expansion or new substation equipment (disconnect switches, circuit breakers, protective relaying, or other auxiliary equipment) on the line terminals other than dedicated metering current and voltage transformers.

The 12-kV and 4-kV distribution systems along the south boundary of the City are fed by feeders out of the Martin and Daly City Substations. The Martin Substation is located in the Brisbane District, just a few blocks south of the city limits. The Martin substation is the major 230/115/60-kV transmission switchyard that serves the San Francisco transmission system, but it also contains an extensive 115/12-kV section that supports approximately 129 MVA of peak load. The majority of this peak load is likely located within the City of San Francisco.

The Daly City Substation is located in the Blossom Valley District, about one mile south of the City boundary and the other side of San Bruno Mountain Park from the Martin Substation (about 2.5 miles west of Martin). The Daly City Substation is fed by a double-circuit 115-kV transmission line from Martin and supports approximately 76 MVA peak load on about 12 feeders. The majority of this load is likely outside of San Francisco due to the geography of the peninsula and the location of the substation, but some Daly City feeders probably cross into the southwest part of the city.

Our GIS database indicates that the border between San Francisco County and San Mateo County has approximately 67 street crossings along the six-mile land-length. We have assumed the number of 4-kV and 12-kV circuits crossing the County border correlates to the number of street crossings. We have also assumed that there are approximately five property parcels adjacent to the County border (both sides) for each street crossing, for a total of 330 customers located on the boundary between the two utilities.

Severance Cost Estimates

The following tables contain planning-level cost estimates for the three approaches to severance. For all three approaches, the scenario and cost associated with the Transmission System Severance remains constant. Please note:

- Cost estimates are at a planning level.
- Costs associated with rendering existing PG&E facilities or capacity underutilized (stranded costs) are not included in the estimates. The only scenario where there may be significant stranded facilities is under Severance Case 3, where a new City-owned substation would replace a majority of the Martin Substation 12-kV capacity and a smaller portion of the Daly City Substation capacity.
- The full severance approach of Severance Case 3 is the only solution that allows the City to obtain all of its power supply exclusively through seven metering points at 115 kV and 230 kV. There may be significant financial and operational ramifications of Fringe Agreements (Severance Case 1) or multiple additional 4/12-kV metering points (Severance Case 2), as compared to the exclusive bulk transmission 115/230-kV interconnections.

Table 2-4
Budgetary Cost Estimate Summary for Severance Case 1

	Quantity	Unit Cost	Subtotal
Transmission System Severance			
Install 230kV CT's and PT's for Revenue Metering at Martin Substation	2 sets	$ 160,000	$ 320,000
Install 115kV CT's and PT's for Revenue Metering at Martin Substation	5 sets	$ 110,000	$ 550,000
Install Revenue Meters, Testing & Commission	7 meters	$ 4,000	$ 28,000
Install Metering Communications at Martin Substation	1 location	$ 10,000	$ 10,000
Distribution System Severance			
Define Service Territories and Implement Fringe Agreements	1 total	$ 100,000	$ 100,000
Subtotal - Construction Costs			$ 1,008,000
Contingency for Planning Level Estimate		30%	$ 302,000
Subtotal - Construction Costs w/Contingency			$ 1,310,000
Engineering Planning & Design		20%	$ 262,000
Construction Permitting and Management		15%	$ 197,000
Owner's Overhead and Financing Costs		15%	$ 197,000
Total Severance Costs			**$ 1,966,000**

Table 2-5
Budgetary Cost Estimate Summary for Severance Case 2

	Quantity	Unit Cost	Subtotal
Transmission System Severance			
Install 230kV CT's and PT's for Revenue Metering at Martin Substation	2 sets	$ 160,000	$ 320,000
Install 115kV CT's and PT's for Revenue Metering at Martin Substation	5 sets	$ 110,000	$ 550,000
Install Revenue Meters, Testing & Commission	7 meters	$ 4,000	$ 28,000
Install Metering Communications at Martin Substation	1 location	$ 10,000	$ 10,000
Distribution System Severance			
Construct Primary Metered Interconnection Point and service disconnect switch at existing 4/12kV circuit crossings, for Overhead Circuit	20 locations	$ 15,000	$ 300,000
Construct Primary Metered Interconnection Point and service disconnect switch at existing 4/12kV circuit crossings, for Underground Circuit	10 locations	$ 40,000	$ 400,000
Reconfigure and reroute 4/12kV Tap and Lateral Circuits	37 locations	$ 5,000	$ 185,000
Confirm and Modify Individual Customer Services	330 services	$ 500	$ 165,000
Subtotal - Construction Costs			$ 1,958,000
Contingency for Planning Level Estimate		30%	$ 587,000
Subtotal - Construction Costs w/Contingency			$ 2,545,000
Engineering Planning & Design		20%	$ 509,000
Construction Permitting and Management		15%	$ 382,000
Owner's Overhead and Financing Costs		15%	$ 382,000
Total Severance Costs			**$ 3,818,000**

Table 2-6
Budgetary Cost Estimate Summary for Severance Case 3

	Quantity	Unit Cost	Subtotal
Transmission System Severance			
Install 230kV CT's and PT's for Revenue Metering at Martin Substation	2 sets	$ 160,000	$ 320,000
Install 115kV CT's and PT's for Revenue Metering at Martin Substation	5 sets	$ 110,000	$ 550,000
Install Revenue Meters, Testing & Commission	7 meters	$ 4,000	$ 28,000
Install Metering Communications at Martin Substation	1 location	$ 10,000	$ 10,000
Distribution System Severance			
Construct new 115/12kV Substation in SE San Francisco to replace severed capacity from existing Martin and Daly City Substations	150 MVA	$ 75,000	$ 11,250,000
Construct 115kV Double-Circuit Transmission Tap to new substation assume route with 50% Underground	1.5 miles	$ 3,000,000	$ 4,500,000
Construct and connect new 12kV Mainline Feeders on PG&E side of system severance boundary, assume 50% Underground	1.0 mile	$ 500,000	$ 500,000
Construct and connect new 12kV Mainline Feeders on San Francisco side of system severance boundary, assume 50% Underground	6.0 miles	$ 500,000	$ 3,000,000
Isolate Existing 4/12kV Distribution Crossings	67 locations	$ 2,000	$ 134,000
Install emergency-use Tie Switches at key interconnection points between the City and PG&E 4/12kV systems	10 locations	$ 10,000	$ 100,000
Confirm and Modify Individual Customer Services	330 services	$ 500	$ 165,000
Subtotal - Construction Costs			$ 20,557,000
Contingency for Planning Level Estimate		30%	$ 6,167,000
Subtotal - Construction Costs w/Contingency			$ 26,724,000
Engineering Planning & Design		20%	$ 5,345,000
Construction Permitting and Management		15%	$ 4,009,000
Additional Permitting for Transmission and Substation Siting		10%	$ 2,672,000
Owner's Overhead and Financing Costs		15%	$ 4,009,000
Total Severance Costs			**$ 42,759,000**

These severance cost estimates, along with distribution, power supply and other costs, become the basis for the economic analysis found in Section 3 of this report.

Section 3

ECONOMIC ANALYSIS

Section 3
ECONOMIC ANALYSIS

R. W. Beck has developed an economic analysis of the purchase of the San Francisco electric distribution system, as defined by the severance and system valuation studies presented under Section 2. The economic analysis projects the net income and cash flow that the City may achieve based on reasonable assumptions about severance costs, system valuation, bond financing, energy sales, bundled electric rates, non-bypassable charges, and other costs. The results of the economic analysis as well as a detailed discussion of the key assumptions are the subjects of this section.

Base Case Analysis and Assumptions

R. W. Beck completed a Base Case analysis to assess the economic benefits/costs of the City purchasing the electric delivery system in San Francisco. The Base Case analysis includes assumptions that are deemed by R. W. Beck to be the most probable to occur. Some of the assumptions used in the first draft report have been changed to reflect additional information provided by PG&E through Data Requests. As part of the public process, PG&E provided written and oral comments on R. W. Beck's first draft report. In response to PG&E's comments, R. W. Beck requested relevant PG&E information that could improve the data inputs and assumptions used in the first draft report. In partial response to R. W. Beck's Data Requests, PG&E has provided energy usage, average rate, and other relevant information for use in the Study. R. W. Beck has incorporated much of the information provided by PG&E in this Final Report. In addition, since the first draft report, the CPUC has issued a decision in the PG&E bankruptcy case that will facilitate the emergence of PG&E from bankruptcy. The CPUC decision clarifies both current and future PG&E retail electric rates. Additional information provided by PG&E and the CPUC bankruptcy decision has affected the assumptions and data inputs used in this Final Report. The following describes the key assumptions used to derive the Base Case forecast.

Energy Sales and Customer Base

In response to R. W. Beck's Data Requests and as a participant in the public process, PG&E has provided energy sales, demand, and number of customers by rate schedule for the City of San Francisco. The following are some of the key characteristics of the energy sales and customer information provided by PG&E:

- The information was provided by rate schedule for each month of 2002 and the first few months of 2003.

- The energy sales and demand figures were broken into residential and non-residential information and then further disaggregated into Time-of-Use (TOU) and non-TOU information.
- The data were also disaggregated into voltage level, firm and non-firm loads (although San Francisco has no non-firm energy sales), Direct Access and non-Direct Access. The Direct Access sales were also disaggregated into continuous Direct Access and non-continuous Direct Access, a distinction made by the CPUC that assigns responsibility for non-bypassable charges. Continuous Direct Access customers do not pay certain non-bypassable charges, but non-continuous Direct Access customers pay all non-bypassable charges.
- Some of the PG&E rate schedules included energy sales and demand but not the number of customers. Therefore, for certain rate schedules, the number of customers was estimated based on class sales and demand in order to calculate class-specific average rates.
- PG&E provided some information on municipal sales but no information on demand or number of customers. Sales for municipal customers were taken from PG&E's comments on R. W. Beck's first draft report.
- For purposes of this Study, the following PG&E rate schedules were assigned to the listed class:

PG&E Rate Schedule	Class Assignment
A-1, A-6, A-15	Small Commercial
A-10, E-19	Medium Commercial
E-20	Large Commercial

The PG&E sales, customers, and demand information was unaudited, unadjusted for billing anomalies, and not weather normalized. However, the information was specific to rate classes and customers in San Francisco and, therefore, represented an improvement over the hourly system load data that was used in the first draft report. The 2002 load and customer information is summarized in Table 3-1 below.

Table 3-1
Estimated Sales by Customer Class

	MWh	Customers	Annual kWh per Customer
Residential	1,336,077	314,061	4,254
Small Commercial	527,393	22,278	23,673
Medium Commercial	1,462,059	8,261	176,983
Large Commercial	1,138,644	1,335	852,917
Municipal	609,130		
Total	5,073,304	345,935	

Annual energy data for 2002 from PG&E was escalated for sales growth from 2003 to 2022 based on peak demand projections taken from the City's electric resource plan Choosing San Francisco's Energy Future prepared by the SFPUC and SF DOE and issued in December 2002. More conservative peak demand growth assumptions were used to prepare model sensitivities presented at the end of this section and in **Appendix A**. The peak demand projections are turned into annual energy sales based on the 2002 system load factor and assigned to class based on the class-specific share of annual energy sales from the data provided by PG&E.

Based on the data provided by PG&E, residential customers in San Francisco outnumber commercial customers nearly 10 to 1, however, commercial load accounts for 62% of total load in San Francisco. Hence, PG&E currently relies more on commercial use than on residential use for energy sales and revenues. The City's customer base consists of about 90% residential, about 9% commercial, and less than 1% industrial. Given the geography and the service area of the City, there is very little load considered agricultural. In addition, there are very minor amounts of energy sales for street lighting, but those loads represent less than 1% of the total San Francisco load and have been excluded from the study. The City's municipal load has been separately identified in the study and is assumed to have an average margin of $0.02 per kWh, resulting from a portion of the load being served at PG&E retail rates in conjunction with Hetch Hetchy power supply costs. The $0.02 per kWh margin is consistent with the margin the City has traditionally earned on sales from Hetch Hetchy. In addition, Direct Access load was identified in the Study, assuming that existing Direct Access customers would receive a cost-based credit from the City when participating in a Direct Access program. In other words, the City would provide a credit for energy costs, transmission charges (if applicable), and certain non-bypassable charges (if applicable) based on the cost the City incurs in providing the services to Direct Access customers. Therefore, any reduction to rates as a result of Direct Access would be directly offset by an equivalent reduction in costs, leaving margins on electric delivery service unaffected. This assumption is consistent with the way in which other California municipal utilities implemented and administered Direct Access programs prior to the suspension of Direct Access.

The City's Retail Rates

If the City were to own and control the distribution system in San Francisco, it would need to determine the ultimate retail rates to be charged its new retail customers. The rate design would likely reflect the City's costs, customer characteristics, legal and political concerns, and competition. The City's electric system would be completely surrounded by PG&E and "rate-to-rate" competition would occur between PG&E and the City. This competition would likely be more political than real, although certain large customers who have a choice on where to locate their operations may attempt to take advantage of any rate differential between the City and PG&E. For the purposes of this analysis, it is assumed the City will charge the same retail rates as PG&E over time. Other municipal utilities have chosen to leave their rates just high enough to pay their costs, leading to sizeable rate differentials between Northern California municipal utilities and PG&E. Rather than just collecting its costs, the City's rates

have been kept the same as PG&E's rates over time in order for the City to evaluate the forecasted NPV of the benefits of purchasing the City's electric delivery system, while the City's rates remain competitive with PG&E.

Because the City's rates are assumed to equal the corresponding bundled PG&E rates by rate class, both current and forecasted PG&E rates are required to model expected net margins over time. Unfortunately, a great deal of uncertainty surrounds the estimation of PG&E retail rates. PG&E was unwilling to share internal projections of PG&E rates. In addition, PG&E has numerous estimates of its current rates based on different sales estimates and assumptions on the financial outcomes of various regulatory cases, including PG&E's bankruptcy case, the 2003 General Rate Case (GRC) settlement, and the long-term procurement case. The outcome of these proceedings will affect PG&E's retail rates for many years to come. Based on the uncertainty of these proceedings, PG&E was unwilling to commit through Data Request responses to a forecast of its average rates over time.

Therefore, for the purposes of this Study, R. W. Beck used the PG&E energy usage, demand, and customer data by rate schedule (described in the previous section) in conjunction with PG&E's current rate tariffs and rules to arrive at the current average rate-by-rate class. It is important to note that in reviewing the data PG&E provided on San Francisco energy sales, it was discovered that San Francisco has very few, if any, customers served on either non-firm rates or at a transmission voltage level rate schedule, both of which would typically lower large customer average rates. Given the absence of non-firm and transmission voltage level load, large customer (E-19 and E-20 PG&E Rate Schedules) current average rates are based on secondary or primary voltage level service, which results in a higher than typical class average rate for large customers. This fact was not captured by PG&E in their comments on R. W. Beck's first draft report but has been incorporated for the purposes of this Study, resulting in a higher overall large customer average rate. All class average rates were calculated first by rate schedule and then aggregated into residential, small commercial, medium commercial, and large commercial classes. R. W. Beck then forecast the current average rates for the duration of the Study based on the following assumptions:

- The CPUC recently issued Final Decision #03-12-035 on December 18, 2003, in the PG&E bankruptcy investigation #02-04-026 that will facilitate PG&E's emergence from bankruptcy court and is based on a Settlement Agreement reached between the CPUC staff and PG&E. The bankruptcy court also issued a separate decision confirming the Reorganization Plan adopted by the CPUC and providing a means for PG&E to reorganize and reestablish investment grade credit ratings. The CPUC Final Decision spells out the terms of the Settlement Agreement with PG&E and the expected rate decreases that will accompany PG&E's emergence from bankruptcy in the first quarter of 2004. Essentially, the Final Decision suggests that PG&E rates will be reduced by about $670 million (net of increases due to PG&E's 2003 GRC settlement), or an average of about 6.2. The Final Decision does not allocate this decrease to rate classes, so for the purposes of this Study, R. W. Beck has assumed that the average 6.2% decrease would apply to all classes equally. Therefore, 2003 class average rates have been reduced by about 6.2% starting in 2004.

- The Final Decision in the PG&E bankruptcy case also requires PG&E to seek permission from the California Legislature during 2004 to add a dedicated rate component to rates to support the issuance of new bonds that would help PG&E restore its investment grade credit rating. The bond issue and dedicated rate component would refinance, and be cheaper than, the current method of adding a regulatory asset with mortgage-style financing to help PG&E emerge from bankruptcy. If PG&E is successful in getting permission for the dedicated rate component/bond issuance from the Legislature, rates would be further reduced by approximately 2% beginning in 2005. This Study assumes that PG&E is successful at the Legislature and that rates will be further reduced by about 2% beginning in 2005.
- Given the term of financing for the proposed regulatory asset or the bond issuance, additional reductions to rates will occur in 2013 when the regulatory asset or bonds are paid off. Therefore, the Study assumed that an additional 4% reduction to rates would occur in 2013.
- Due to changes in non-bypassable charges over time, PG&E's retail rates can be expected to decline as non-bypassable charges are paid off. Specifically, PG&E rates have been reduced in 2009 to reflect removal of the Fixed Transition Amount (FTA) from rates and in 2014 and 2019 to reflect removal of "Tail" CTC. Additional reductions to PG&E rates to remove the effect of CDWR contract costs on the average cost of PG&E's energy resources have also been made.
- Other than the reductions to rates specified above, the Study assumes rates will be increasing by inflation for the duration of the Study, as PG&E will be returning to a more traditional GRC/attrition regulatory process that will allow PG&E to capture inflationary trends in rates annually. Inflation is applied to only those components of the rates that are subject to inflation (about 70% of the bundled rate). Inflation was forecast based on the Blue Chip Economic Indicators October 2003 report through the duration of the Study.
- Average rates were also adjusted annually based on changes in market power supply costs. A portion of PG&E's energy resources comes from purchases of energy at market prices. As market energy prices change, the average cost of PG&E's resource portfolio also changes. Changes to PG&E's average cost of energy resources have been captured within the PG&E rate projections used in this Study.

Power Supply Costs

This Study assumes that all of the City's energy requirements will be met using new energy contracts, short or long term. Market prices are estimated from the CEC's study Electricity Infrastructure Assessment issued in May 2003. The CEC's study period covered 2004 through 2013. Prices from 2013 through the duration of the Study are escalated at the rate of inflation forecast by the publication Blue Chip Economic Indicators (October 2003).

The City may have other options for power procurement. Power from the City's renewable portfolio, the Williams Company natural gas turbines, or from Hetch Hetchy may be available to help provide for City loads. To the extent these resources are available to the City, it may be capable of cutting the overall cost of its power supply portfolio relative to future market power costs.

Expenses

Distribution O&M and Other Operating Costs

For the purpose of financial feasibility, it has been assumed that the annual distribution O&M and other operating costs for the City would be about equal to similar PG&E O&M and other operating costs, although increased capital costs for renewals and replacements reflect the age and condition of the City's distribution system. It is assumed the City would have similar maintenance, planning, and construction standards as PG&E, and the costs to maintain and operate the distribution system and service customer accounts in San Francisco would be roughly equivalent. Therefore, costs for customer service, distribution operations, administrative and general expenses, uncollectibles, and wage and other cost changes were assumed to be the same as PG&E's. Costs for both distribution O&M and the other operating costs were calculated from the Settlement Agreement filed in PG&E's 2003 (GRC). The Settlement Agreement was filed in August 2003 and contains detailed information about PG&E's latest distribution O&M and other operating costs that are very likely to be ultimately included in rates. Based on Exhibit PG&E-6 (Chapter 2, Table 2-3) and Chapter 14 (Table 14-5), PG&E's average distribution O&M per kWh is about $6.44 per MWh and other operating costs average about $6.00 per MWh. These costs are scaled up by the Blue Chip Economic Indicators October 2003 projections of inflation from 2003 through the duration of the Study. Other operating costs include taxes appropriate for a municipal utility, as well as the effect of lost franchise fees and property taxes resulting from taking over the distribution system from PG&E.

Transmission

Transmission service into the City is currently provided by both PG&E and the City. The City owns, maintains, and manages transmission facilities sufficient to deliver Hetch Hetchy power to municipal loads within the City. However, the City's transmission ends south of San Francisco and PG&E transmission lines carry Hetch Hetchy power the rest of the way into San Francisco. The City's Transmission Interconnection Agreement with PG&E governs the delivery of this power along PG&E lines into the City. Should the City take over the rest of the City's loads through purchase of the electric delivery system in San Francisco, the City is required by the interconnection agreement to renegotiate the terms of the agreement with PG&E in good faith. If the parties are unable to reach a new agreement within six months of initial negotiations, then either party may terminate the agreement. Transmission service sufficient to meet the new load is therefore assumed to come through CAISO tariffs, as the CAISO would have operational authority over the lines interconnecting the City's transmission facilities south of San Francisco, with the rest

of the City's electric delivery system. Currently, the CAISO tariffs require transmission users to pay a Transmission Access Fee (TAC), a Grid Management Charge (GMC), congestion management fees, and ancillary services costs. Historically, these costs have been about 8% to 12% of the total cost of a utility's power portfolio. However, FERC, in conjunction with potentially the U.S. Congress and other market participants, is attempting to redesign the transmission market structure and the way in which transmission operators and owners manage congestion. FERC is proposing a Locational Marginal Pricing model that will likely raise transmission congestion management fees for areas of the transmission grid that have historically been congested. Because transmission into San Francisco is typically congested and constrained, San Francisco's cost for CAISO service is likely to rise, especially if the Jefferson-to-Martin transmission expansion proposed by PG&E is not built. Although the City may have other options to using CAISO transmission service (build or expand its own transmission, more in-City generation), for the purpose of this Study, transmission is assumed to cost 15% of the City's total energy portfolio costs.

Non-Bypassable Charges

In dealing with the financial aftershocks of the 2000-2001 energy crisis, the California Legislature and CPUC made it very clear that, as the electric market structure continued to change, customers would not be able to avoid certain costs allocated to them as a part of initial electric restructuring or the energy crisis. Beginning in 2002, the CPUC began to define the costs that customers who bypass one or more Investor-Owned Utility (IOU) service would pay after they bypass. These costs have been defined by the CPUC as Cost Responsibility Surcharges (CRS) and apply mainly to certain Direct Access customers, customers who are served under an AB 117 Community Aggregation Plan, and customers who bypass the IOU's electric delivery services either through cogeneration or purchase of certain electric facilities. The CRS that eventually is paid by each of these groups of bypass customers could be very different. In addition, the CRS that applies to each customer class (residential, commercial, and industrial) is also likely to be different. A CRS is certain to apply to the customers of any new municipal electric distribution utility in San Francisco. While decisions regarding the composition of these charges (who they would apply to, the amount of the charges, and how long the charges would apply) are all still evolving, the following describes the type and size of the CRS that was assumed to apply for the purposes of this Study.

CDWR Energy Contract Costs, Bond Repayments, and Other Costs

The California Department of Water Resources (CDWR) took over purchasing obligations for the California's IOUs in January 2001. The CDWR purchased billions of dollars' worth of energy during the summer and fall of 2001 that was eventually amortized and is assumed to be paid for through a bond issue over the next 20 years. In addition, the CDWR signed many long-term contracts that have turned out to be far in excess of the market price of power over the long term. The cost of the contracts above-market prices is absorbed by all of the IOUs' customers, including those

customers that choose to bypass IOU service. The CPUC issued Decision #02-11-022 in 2002 that determined how much cost responsibility certain Direct Access customers would have for newly signed CDWR energy contracts, bond costs, and other CDWR administrative and management costs. The surcharge for these customers was initially capped at $0.027 per kWh.

The CPUC recently issued Decision #03-07-028 that determined the CRS that would apply to Municipal Departing Load (MDL), which is "… departing load served by a 'publicly owned utility' as that term is defined in Public Utilities Code Section 9604(d), including municipalities or irrigation districts." The CRS that applies to MDL load for CDWR costs is assumed to equal $0.027 per kWh for all customers until 2011, when large shares of the CDWR contracts expire. After 2011, the $0.027 per kWh is reduced in half through 2013 and then reduced again by 50% from 2014 through 2018, when the CDWR contracts will be negligible and have virtually no affect on rates. While there is evidence that some Commissioners and other parties believe the charge should be higher in the short term and lower over time, the current majority of Commissioners have twice ruled that the $0.027 per kWh charge is appropriate for customers similar to MDL. The CPUC in Decision #03-07-028 also ruled that there will not be a cap on the CDWR component of the CRS that applies to MDL and that the IOUs are required to file tariffs that spell out the cost of each component of the CRS. Those filings have not yet been made and, in absence of any other evidence that the CPUC is going to imminently change its policy toward the CDWR component of the CRS, R. W. Beck has assumed that the $0.027 per kWh would apply to all of the City's energy sales.

Nuclear Decommissioning Costs (NDC)

NDC charges are defined by the Public Utilities Code to be non-bypassable. The charges included in this Study were based on PG&E's current unbundled tariff that shows the rate component for NDC charges by customer class.

Post-Transition Period Competition Transition Charge (Tail CTC)

Tail CTC is also defined as a non-bypassable charge under Public Utilities Code regulations. Tail CTC is composed of mainly the above-market costs associated with an IOU's Qualifying Facility and other long-term contracts, as well as other restructuring costs (including employee restructuring costs). Tail CTC is assumed to average $0.01 per kWh for all customer classes through 2013 and then drop to $0.005 per kWh from 2013 to 2018. After 2018, the tail CTC is assumed to be paid off and the contracts expired or restructured.

FTA

The FTA was originally designed to pay for the Rate Reduction Bonds used during industry restructuring to provide a 10% discount to residential and small commercial customers. The FTA is a non-bypassable charge and generally applies to customers with peak demands of less than 20 kW. The FTA charges included in this Study were based on PG&E's current unbundled tariff that shows the rate component for FTA

charges by customer class. The FTA is scheduled to terminate when the Rate Reduction Bonds are paid off in 2008.

Public Purpose Programs

Public purpose programs are assumed to be 2.85% of total revenues.

Total CRS

Table 3-2 shows the initial amount of CRS included for this Study. All CRS is assumed to expire in 2018.

Table 3-2
Assumed CRS in 2004

	Rate Schedule	CTC ($/kWh)	NDC ($/kWh)	FTA[3] ($/kWh)	CDWR Costs ($/kWh)
Residential	E-1, E-7, E-8, E-9	0.01	.00048	.00969	.027
Small Commercial	A-1, A-6, A-15	0.01	.00056	.01056	.027
Medium Commercial	A-10, E-19	0.01	.00038	.01219	.027
Large Commercial	E-20	0.01	.00028	N/A	.027

Financing Costs

The amount to be financed includes the amount to be paid for the system, $60 million for costs of acquisition and working capital, plus one year's debt service to fund debt service reserves.

Interest rates are based on a conservative estimate of the financing costs for San Francisco, assuming that interest earnings are subject to federal tax but not state tax. That interest rate is 6.25%. Debt service is calculated on the basis of 30-year level debt service requirements.

These assumptions produce a higher than expected annual debt service because a portion of the capital requirements can be financed with tax-exempt debt. Taxable debt is required only for the actual cost of facilities purchased from PG&E. Tax-exempt debt can be used for severance costs, working capital, costs of acquisition, and reserves.

Renewals and Replacements

Renewals and replacements have been estimated on the basis of the average of the last seven years of capital expenditures provided by PG&E in response to R. W. Beck's Data Requests. It is assumed that these capital expenditures will be financed using tax-exempt debt with an interest rate of 5.0%. Debt service is calculated assuming

[3] The FTA applies to small commercial customers who have elected to take service from Medium Commercial Rate Schedules A-10 or E-19V.

30-year level debt service adjusted for the additional renewal and replacement requirements each year. The utility will have the option of paying for some or all of these expenditures from net revenues, depending on annual operating results and its financial Business Plan.

Table 3-3 summarizes the projected results of the Base Case analysis based on all the assumptions enumerated above and three values for the electric assets.

Table 3-3
Base Case Results

	Base Case		
	Low Value	**Mid Value**	**High Value**
Distribution System Cost	720,000,000	1,120,000,000	1,520,000,000
Severance Cost	1,966,000	3,818,000	42,759,000
20-year NPV ($000)	1,346,881	1,003,021	627,424
Average Retail Rate	0.1333	0.1333	0.1333
Average Break-Even Rate	0.1123	0.1181	0.1245

According to the analyses summarized in Table 3-3, the City can expect a positive NPV from the purchase of the electric delivery system in San Francisco under the entire range of system valuation costs. In addition, annual net income remains positive in all years under all three system valuations. The positive annual net income depends heavily on the retail rates charged by the City, the power prices paid, and assumptions on load growth. Scenarios involving these key variables are discussed below. Overall, the City should be able to maintain positive net income while charging PG&E rates for the duration of the Study. The Pro Formas for the three Base Cases are included in **Appendix A**.

Scenario Analysis

R. W. Beck also completed a sensitivity analysis to determine the NPV of purchasing the electric delivery system under varying conditions. Table 3-4 shows the results of this analysis.

Table 3-4
Sensitivity Analysis

	Scenario 1	**Scenario 2**
Distribution System Cost	$720,000,000	$1,520,000,000
Severance Cost	$1,966,000	$42,759,000
20-year NPV ($000)	$2,182,731	($179,085)
Average Retail Rate	$0.1333	$0.1333
Average Break-Even Rate	$0.0992	$0.1405

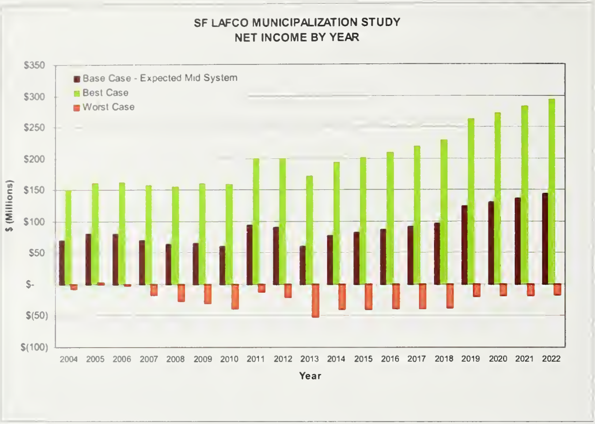
Table 3-4 shows that the purchase of the system is not economic under the conditions contained in Scenario 2. However, under Scenario 1 conditions, the purchase of the system is expected to bring in an average annual net income of about $202 million per year. All of the assumptions from the Base Case apply to Scenarios 1 and 2, with the following changes:

- Scenario 1 assumption changes:
  - The CEC market price forecast was decreased by 20% to reflect the effects of potentially good statewide hydroelectric availability, low gas prices, low electric demand growth, and a low-cost estimate of power generation.
  - San Francisco's load increased at an average of over 2%.
  - The low-cost valuation and severance estimates were assumed.
- Scenario 2 assumption changes:
  - The CEC market price forecast was increased by 20% to reflect the effects of potentially low statewide hydroelectric availability, high gas prices, high electric demand growth, and a high-cost estimate of power generation.
  - San Francisco's load was held stagnant with no growth.
  - The high-cost valuation and severance estimates were assumed.

The Pro Formas for Scenarios 1 and 2 are included in **Appendix A**.

Graph 3-1 below shows the net income annually for Scenarios 1 and 2 and for the Base Case, with a mid-system value. Net income is expected to be positive in all years in the Base case and the Best Case. In the Worst Case, net income is negative in most years. The graph illustrates how sensitive net income is to changes in load growth or power supply cost assumptions. Clearly, if there were little to no retail load growth, relatively high power prices, and the City paid a high price for the delivery system, net income could be negative, resulting in rates higher than PG&E's expected bundled rates.

Graph 3-1
Net Income by Year



Section Summary

According to two of the three scenarios, the City could expect to have a positive NPV from the purchase of the electric delivery system in San Francisco. Scenario 2, where energy prices were increased by 20%, growth was held stagnant and the high-cost acquisition was assumed did not show a positive NPV. This scenario shows the effects that fluctuating loads or energy prices could have on the City's financial outcomes. There are a number of risks the City would be exposed to as part of the purchase of the system that could diminish its value. These risks are explored further in Section 4 of this report.

Section 4

RISK MANAGEMENT

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Section 4
RISK MANAGEMENT

Owning, operating, managing, planning, and developing retail electric distribution, transmission, and generation services involves many risks. As SF LAFCO evaluates the potential for providing electric delivery (distribution and transmission) and generation services to the citizens of the City, SF LAFCO is wise to consider those risks. This section describes the Enterprise Wide Risk Assessment (EWRA) that is currently being conducted at the SFPUC for HHWP, R. W. Beck's approach to the EWRA, and identifies key risks faced by the City in purchasing the electric delivery system.

The risk management work that is currently being performed for the SFPUC is limited to the current operations of HHWP. If acquisition were to take place, an expanded risk management effort would be required to protect against power supply volatility, and the risks associated with the ownership and operation of a distribution utility.

SFPUC EWRA

R. W. Beck has been retained by the SFPUC to conduct an EWRA of the HHWP enterprise. The project consists of the following five tasks:

Task	Description
1	Enterprise Wide Risk Assessment
2	Development of Risk Management Strategy
3	Specification of Risk Metrics and Quantitative Tools
4	Development of Risk Management Policy and Procedures Manual
5	Implementation Support

Task 1 is a qualitative analysis of HHWP's overall organizational risks, including a qualitative assessment of the trade-offs between HHWP's water first priority and power supply or The Raker Act obligations. Tasks 2 and 3 rely on the results from Task 1 to develop analytical models for determining HHWP's financial exposure to the various risks identified in Task 1. Task 4 is development of risk management policies and procedures (risk limits, risk analytics and reporting, risk organizational structure, transaction execution rules, etc.) that recognize HHWP's unique organization structure, and political and market environments. Task 5 will be to assist HHWP in implementing the report recommendations from previous tasks.

EWRA Approach

Fundamentally, risk management involves identifying and mitigating, as appropriate, those factors that could interfere with achievement of the organization's objectives. A working definition of risk is "any event or condition that could cause adverse financial performance compared to expectations." This definition is intentionally broad, so as not to exclude potential risk sources that may be deserving of management attention. The key to successful risk management is to be able to understand and manage these various sources of risk, ultimately under an enterprise wide framework. For an energy risk management program to be complete, it must be built around a framework that addresses the following five elements: Organizational Objectives, Risk Tolerance, Risk Inventory, Portfolio Management, and Risk Control Infrastructure.

Organizational Objectives

It is critical to articulate goals, strategies, and objectives that provide guideposts that define the appropriate hedging, trading, and portfolio management activities to be undertaken by the organization, as well as those activities that are inappropriate.

Risk Tolerance

Through risk tolerance definition, the organization should specify the amount of uncertainty that the organization is willing to accept in its future financial performance, with particular emphasis on the organization's tolerance for falling short of financial expectations.

Risk Inventory

Through the energy risk management program, the organization should characterize the types and magnitudes of risks to which the organization is exposed and which contribute to the potential for adverse financial performance.

Portfolio Management

Organization personnel must engage in strategic (longer term) and tactical (shorter term) transaction activities in order to help maintain risk exposures within the organization's risk tolerance and reduce the probability of falling short of financial expectations. The ability to successfully conduct these types of transactions also enables the capturing of low-risk opportunities that can further enhance financial performance.

Risk Control Infrastructure

Best practices dictate that a collection of internal controls, systems, and operating practices are necessary for the organization to achieve the objectives of its risk management program. The Risk Control Infrastructure includes:

- Policies and Procedures
- Organization Structure and Responsibilities with Clear Separation of Duties
- Limits for Risk Exposures and Transactions
- Position Tracking
- Risk Measurement
- Performance Measurement
- Management Reporting

High-Level Risk Inventory

This section of the report details some of the high-level risks that any entity will face in owning, operating, managing, and developing electric service within the City. The magnitude of the identified risks suggests that near-term management attention would be needed after establishment of the municipal authority in order to appropriately manage and mitigate the inherent risks. Near-term management attention would be the development of an EWRA, quantitative modeling and analysis of the risks, and development of risk management policies and procedures to establish firm-wide priorities and practices in dealing with risk. The risks are not presented in a particular order.

Volumetric Risk (Power Generation)

Even though the evaluations included economic analyses, it did not include the economic benefit of integrating low-cost Hetch Hetchy power or the Williams Company turbines into the power supply costs. If municipalization occurs, these resources would be included in any risk management program.

Power generation for the City can come from a number of sources, including potentially Hetch Hetchy hydroelectric generation, the new Williams Company natural gas turbines, the City's renewable energy portfolio, and other market purchases. All potential sources of energy and capacity have significant risks associated with them. Hetch Hetchy hydroelectric generation may not be available to the City at all due to The Raker Act obligations, seasonal hydrology, or other pre-existing contractual commitments and would need to have firming power associated with it. The Williams Company turbines would only be available for the City under the terms of the Power Purchase Agreement between the City and CDWR until its expiration. In addition, there is still no guarantee that the turbines will be located within the City and permitted for City use. The turbines will also expose the City to potentially volatile natural gas markets. The City's renewable portfolio has not yet been built and the

amount of energy and capacity at low prices will be limited. Short-term or long-term energy purchases can be both volatile and expensive and are typically a source of significant risk. Any generation resources or contracts will need to be carefully evaluated, negotiated, developed, and managed in order to ensure the City is able to minimize both its overall cost of power and its risk exposures.

Volumetric Risk (Energy Sales)

Although San Francisco's load shape is relatively flat with a fairly high load factor, San Francisco's load is still driven mainly by weather conditions. Changing weather patterns that persist through an entire season (a cold winter or hot summer) can have a material impact on energy sales. Variability in energy sales will cause revenues and costs to fluctuate. Depending on how well revenues respond through the retail rate structure to changes in costs, the City could be exposed to significant financial risk as a result of variability in energy sales.

Market Price Risk (Gas)

If the City is successful in developing, installing, operating, permitting, and managing the Williams Company turbines currently available to it, the City will need to carefully manage natural gas prices in order to maximize the benefits of the proposed turbines. The City's exposure to gas prices will significantly increase once the City's Power Purchase Agreement with CDWR expires. In addition, the City will need to ensure that it has adequate firm natural gas transportation, and will need to develop an adequate and risk-adjusted Fuel Supply Plan.

Market Price Risk (Power)

In addition to volumetric risks, the City would also be exposed to significant market price volatility. Price and volume volatility can create situations when sales revenues can fall significantly below expectations, while power costs can significantly exceed expectations. This process could occur when San Francisco's unique microclimate and power market is inconsistent with the rest of California.

Operational Risk

Being a service run for the first time by the City, whatever agency takes over management and regulation of electric delivery services in the City could manage its risks through the establishment of appropriate policies and procedures. The policies and procedures would provide the organization a guideline to use in mitigating risks. To the extent the policies and procedures are clear, well understood, disseminated, and have the buy-in of affected parties, they should be effective in helping to mitigate risk.

Regulatory Risk

There are numerous sources of regulatory risk associated with electric service. The CPUC believes it has the authority to assign non-bypassable charges to new municipal

entities and customers. In two recent decisions in Rulemaking 02-01-011, the CPUC ruled that both new municipalities and municipalities that expand into an existing IOU service area are subject to non-bypassable charges (CRS), including CDWR power contract and bond costs and tail CTC. FERC is currently debating and developing the rules for management of electric transmission markets nationwide. The City would have the option of building its own transmission network (which carries its own set of risks) or interconnecting with PG&E into CAISO. In the latter scenario, the City would be fully exposed to CAISO transmission charges and congestion management fees. Under FERC's Standard Market Design and Locational Marginal Pricing model and due to the limited capacity of transmission serving the San Francisco peninsula, congestion fees for power delivery into San Francisco are likely to significantly increase, unless additional transmission capacity is built to deliver power into and around the City. The California Legislature, although not anxious to restructure the electric industry after the problems caused by the passage of AB 1890, is debating bills that would have a significant impact on California's electric market structure for many years, including the potential return of Direct Access that the City would need to compete with. Finally, the rate structure and ongoing financial stability of PG&E will help determine what the City could reasonably charge for its service. The emergence of PG&E from bankruptcy, the ultimate price of PG&E's retained generation, the expiration of CDWR contracts, the price and type of replacement power for these contracts, the renewable portfolio standard, and other PG&E rate-related issues (GRCs, attrition cases, cost of capital cases, distribution and transmission needs, etc.) will all have a long term impact on the ability of the City to stay competitive and operate a financially viable electric municipality.

Institutional Risk

Institutional risk relates to influences that outside organizations can have on the potential municipality. The potential new municipal utility could be part of the broader SFPUC and would ultimately be controlled by City government, although reporting to either its own Board or to the SFPUC Commissioners. Given this organization, the new municipal utility may be subject to significant outside influence and regulation and could potentially have numerous stakeholder interests in its operations and financial results. In addition, as a public entity, the new municipal utility would ultimately answer to the people of San Francisco, its major power customers. Given the numerous stakeholders, the new municipal utility would have substantial institutional risk as stakeholders work through various venues to create change and achieve their objectives. Coordination on policy-level issues between key stakeholders is important to managing institutional risk.

Delivery Risk (Distribution and Transmission)

Delivery of energy at either low or high voltage can entail significant risks. PG&E has recently been heavily criticized and fined by regulatory authorities for poor distribution reliability within San Francisco. Based on R. W. Beck's review of the City's electric infrastructure, the current system is in need of significant investment if reliability is to be maintained. The public's scrutiny of electric delivery infrastructure

reliability and their expectations of good performance and operation of the delivery assets will not change if the City moves forward with taking over the electric delivery system in the City. The City would need to move quickly and budget appropriately to ensure the current system would provide adequate reliability at start-up of the City's takeover. If the City owned and operated the electric delivery system, the City would be exposed to risks associated with significant outages or system problems, equipment failures, acts of terrorism or sabotage, public works coordination and construction management, and the use of public funds for ongoing maintenance and development of the electric delivery system.

Political Risk

Taking over the electric delivery system in the City requires purchasing or compensating PG&E for the system. PG&E is very protective of its distribution and transmission assets and sees any threat of takeover of those assets as an affront to their core business. PG&E is very likely to strongly oppose any takeover attempt by the City, including spending significant sums of money on public outreach, advertising and education, political pressure, and legal/expert analysis and defense. In addition to PG&E's response, the takeover of the delivery system would take significant commitment of funds from City decision-makers over extended periods of time. The City's leaders and citizens would need to maintain their commitment in the face of likely significant PG&E opposition. The political risk associated with takeover of the delivery assets would likely be very high.

Section 5

CONCLUSIONS AND RECOMMENDATIONS

Section 5
CONCLUSIONS AND RECOMMENDATIONS

Based solely on the economic analysis and the scenario analysis in Section 3 of this report, it would appear that it is in the City's best long-term interest to continue to pursue the acquisition of transmission and distribution facilities within San Francisco. Under most cases, even with conservative assumptions, it would appear that over the long term, savings could be achieved for the San Francisco ratepayer. Base Case scenario NPV savings range from \$0.75 billion to \$1.47 billion, depending on assumptions regarding the cost of the distribution system and severance from PG&E.

Table 5-1
Base Case Results

	Base Case		
	Low Value	**Mid Value**	**High Value**
Distribution System Cost	720,000,000	1,120,000,000	1,520,000,000
Severance Cost	1,966,000	3,818,000	42,759,000
20-year NPV (\$000)	1,469,178	1,125,318	749,721
Average Retail Rate	0.1369	0.1369	0.1369
Average Break-Even Rate	0.1124	0.1182	0.1246

The technical assessment raises some concerns that should be considered and discussed before a decision is made with regard to acquisition of existing facilities in San Francisco. The age and condition of the system present challenges and risks to the City that could make its acquisition undesirable. A large portion of the residential and strip commercial areas of the City are served by a 4-kV system that is becoming obsolete. The network system serving the central business section of the City, although highly reliable, is expensive to maintain. Substantial improvements will need to be made to large sections of the distribution system in the years to come. If the cost of acquiring the system is on the high end of the estimate and the City ultimately has to abandon or overbuild significant portions of the system, it might not be worth the cost of acquisition.

The following table outlines our perceived major benefits and risks for San Francisco, should it proceed with the acquisition of PG&E's transmission and distribution facilities.

Table 5-2
Electric System Acquisition

Benefits	Risks
▪ Economic analysis indicates likelihood of ratepayer savings over the long term.	▪ Age and condition of system.
▪ City-owned resources could provide further savings.	▪ Protracted fight with PG&E.
▪ Greater control over investment/reliability.	▪ Variability of costs, revenues, and market prices.

The economic analysis indicates that NPV savings could be achieved under most scenarios. In addition, the integration of City-owned resources provides both a hedge to higher prices and less reliance on market purchases. Integration of these resources into the plan would tend to improve the economics over time. Finally, the City could exert greater influence and control over investment and reliability decisions through acquisition.

There are three significant risks associated with acquisition. The first is the age and condition of the system. The City would need to be very careful not to pay significantly more than the system is worth, and must also be prepared to invest in the improvement and upgrade of the system. Much of the distribution system in San Francisco is 4-kV circa 1950s. In addition, the downtown network system is complex and costly to maintain.

The second major risk is the reaction from PG&E to an attempt to acquire existing facilities. The City can expect PG&E to contest the acquisition of existing facilities with fierce opposition and considerable legal and political resources. The City must be prepared to deal with these issues if the acquisition stands a chance of succeeding. Historically, very few communities have been able to withstand this kind of intense opposition.

Finally, the City would need a sound management plan to deal with the major risks of owning and operating an electric delivery system and supplying retail load. The sensitivity analysis determined that realistic changes in load, market prices, retail rates, and potential changes in other costs could eliminate identified savings.

Recommendations

Based on the technical assessment, economic analysis, and risk management considerations, R. W. Beck submits the following recommendations for SF LAFCO's consideration.

1. Proceed with acquisition alternative – a detailed appraisal.
2. Evaluate cost-benefit of facilities' acquisition during detailed valuation process. Some sections of the system may be less costly to replace than to acquire.

3. Power supply options can be pursued immediately through implementation of AB 117 and later integrated if the acquisition of other facilities occurs.
4. Develop a sound management plan to deal with the major risks of owning and operating an electric delivery system and supplying retail load.

Given the outcome of the economic analysis, further detailed consideration of transmission and distribution system acquisition appears warranted. This can be achieved through a thorough evaluation and appraisal of the existing facilities. Care should be taken in order to determine, as a result of this process, which facilities are salvageable, at what reasonable cost, and what facilities need to be replaced in their entirety. Such a complete system appraisal is likely to take six months to perform from start to finish and is estimated to cost approximately $500,000 to $600,000.

Regardless of what happens with Recommendations 1. and 2. above, the findings of this analysis further support and reinforce the earlier studies that determined that implementation of AB 117 is in the best interest of San Francisco.

Finally, the City should consider the political and legal consequences of pursuing these actions. The process of acquiring facilities from an unwilling seller with the resources and clout of PG&E would most likely be time consuming and costly.

Appendix A

PRO FORMAS

Base Case: Expected with Mid System Cost

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	CUSTOMERS/LOAD																				
	Load (MWh)																				
	Residential	1,362,799	1,390,055	1,417,856	1,439,124	1,453,515	1,468,050	1,482,730	1,497,558	1,512,533	1,527,659	1,542,935	1,558,365	1,573,948	1,589,688	1,605,585	1,621,640	1,637,857	1,654,235	1,670,778	1,687,486
	Commercial																				
	Small	537,941	548,699	559,673	568,069	573,749	579,487	585,282	591,134	597,046	603,016	609,046	615,137	621,288	627,501	633,776	640,114	646,515	652,980	659,510	666,105
	Medium	1,491,301	1,521,127	1,551.549	1,574,822	1,590,571	1,606,476	1,622,541	1,638,766	1,655,154	1,671,706	1,688,423	1,705,307	1,722,360	1,739,584	1,756,979	1,774,549	1,792,295	1,810,218	1,828.320	1,846,603
	Large	1,161,417	1,184,646	1,208,338	1,226,464	1,238,728	1,251,115	1,263,627	1,276,263	1,289,026	1,301,916	1,314,935	1,328,084	1,341,365	1,354,779	1,368,327	1,382,010	1,395,830	1,409,788	1,423,886	1,438,125
	Municipal	609,130	621,313	633,739	643,245	649,677	656,174	662,736	669,363	676,057	682,817	689,646	696,542	703,508	710,543	717,648	724,824	732,073	739,393	746,787	754,255
	Total Load at Meter	5,162,587	5,265,839	5,371,156	5,451,723	5,506,240	5,561,303	5,616,916	5,673,085	5,729,816	5,787,114	5.844.985	5,903,435	5,962,469	6,022,094	6,082,315	6,143,138	6,204,569	6,266,615	6,329.281	6,392,574
	Less Direct Access	517,218	527,562	538.113	546,185	551,647	557,163	562,735	568,362	574,046	579,786	585,584	591,440	597,354	603,328	609,361	615,455	621,609	627,825	634,104	640,445
	Load Served (MWh)	4,645,370	4,738,277	4,833,043	4,905,538	4,954,594	5,004,139	5,054,181	5,104,723	5,155,770	5,207,328	5,259,401	5,311,995	5,365,115	5,418,766	5,472,954	5,527,683	5,582,960	5,638,790	5,695,178	5,752,129
	Losses @8.0% (MWh)	371,630	379,062	386.643	392,443	396,367	400,331	404,334	408,378	412,462	416,586	420,752	424,960	429,209	433,501	437,836	442.215	446,637	451,103	455,614	460,170
	Energy Requirement	5,016,999	5,117,339	5,219,686	5,297,981	5,350,961	5,404,471	5,458,515	5,513,100	5,568,232	5,623,914	5,680,153	5,736,954	5,794,324	5,852,267	5,910,790	5,969,898	6,029,597	6,089,893	6,150,792	6,212,300
	Market purchases	5,016,999	5,117,339	5,219.686	5,297,981	5,350,961	5,404,471	5,458,515	5,513,100	5,568,232	5,623,914	5,680,153	5,736,954	5,794,324	5,852,267	5,910,790	5,969.898	6,029,597	6,089,893	6,150,792	6,212,300
	PRICES																				
	Market Electricity ($/MWh)	$ 30.00	$ 34.67	$ 32.27	$ 34.02	$ 37.08	$ 39.62	$ 41.40	$ 43.81	$ 45.69	$ 48 36	$ 50.68	$ 52.00	$ 53.35	$ 54.74	$ 56.16	$ 57.62	$ 59.12	$ 60.66	$ 62.24	$ 63.86
	DWR Bond Repayment ($/MWh)	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 13.50	$ 13.50	$ 13.50	$ 6.75	$ 6.75	$ 6.75	$ 6.75	$ 6.75	$ -	$ -	$ -	$ -
	Distribution O&M ($/MWh)	$ 6.08	$ 6.08	$ 6.08	$ 6.23	$ 6.38	$ 6.53	$ 6.69	$ 6.85	$ 7.02	$ 7.20	$ 7 38	$ 7.56	$ 7.75	$ 7.94	$ 8.14	$ 8.34	$ 8.55	$ 8.77	$ 8.99	$ 9.21
	Transmission ($/MWh)	$ 4.50	$ 5.20	$ 4 84	$ 5.10	$ 5.56	$ 5.94	$ 6.21	$ 6.57	$ 6.85	$ 7.25	$ 7.60	$ 7.80	$ 8.00	$ 8.21	$ 8.42	$ 8.64	$ 8.87	$ 9.10	$ 9.34	$ 9.58
1	Rates ($/kWh)																				
	Residential	$ 0.1336	$ 0.1257	$ 0.1248	$ 0.1268	$ 0.1290	$ 0.1312	$ 0.1244	$ 0.1268	$ 0.1215	$ 0.1244	$ 0.1221	$ 0.1146	$ 0.1175	$ 0.1204	$ 0.1234	$ 0.1265	$ 0.1209	$ 0,1240	$ 0.1272	$ 0.1305
2	Commercial / Industrial																				
	Small	$ 0 1811	$ 0.1703	$ 0.1695	$ 0.1726	$ 0.1759	$ 0.1792	$ 0.1728	$ 0.1764	$ 0.1724	$ 0.1765	$ 0.1734	$ 0.1673	$ 0.1715	$ 0.1757	$ 0.1801	$ 0.1846	$ 0.1805	$ 0.1852	$ 0.1899	$ 0.1948
	Medium	$ 0.1470	$ 0.1383	$ 0.1374	$ 0.1398	$ 0.1422	$ 0.1447	$ 0.1444	$ 0.1471	$ 0.1422	$ 0.1454	$ 0.1426	$ 0.1356	$ 0.1388	$ 0.1421	$ 0.1455	$ 0.1489	$ 0.1438	$ 0.1474	$ 0.1510	$ 0.1548
	Large	$ 0.1366	$ 0.1285	$ 0.1277	$ 0.1297	$ 0.1320	$ 0.1342	$ 0.1364	$ 0,1389	$ 0.1337	$ 0.1366	$ 0.1339	$ 0.1266	$ 0.1295	$ 0.1325	$ 0.1356	$ 0.1387	$ 0.1333	$ 0.1365	$ 0.1398	$ 0.1432
	Direct Access Average Credit ($/MWh)	$ 37.35	$ 42.72	$ 39.96	$ 41.97	$ 45.49	$ 48.41	$ 50.46	$ 53.23	$ 53.97	$ 57.04	$ 59.71	$ 60.51	$ 62.07	$ 63.66	$ 65.30	$ 66.98	$ 67.99	$ 69.76	$ 71.57	$ 73.43
3	**REVENUES ($000)**																				
	Residential	$ 182,070	$ 174,745	$ 176,986	$ 182,543	$ 187,523	$ 192,588	$ 104,506	$ 189,861	$ 183,835	$ 189,976	$ 188,348	$ 178,666	$ 184,926	$ 191,407	$ 198,116	$ 205,063	$ 197,998	$ 205,167	$ 212,592	$ 220,281
	Commercial / Industrial																				
	Small	97,421	93,425	94,886	98,065	100,921	103,841	101,136	104,259	102,925	106.432	105.607	102,899	106,523	110,275	114,160	118,182	116,718	120,920	125,271	129,776
	Medium	219,221	210,342	213,245	220,096	226,242	232,505	234,313	241,065	235,392	243.064	240,819	231,197	239,052	247,183	255,597	264,307	257,720	266,747	276,092	285,767
	Large	158.650	152,257	154,245	159,115	163,480	167,923	172,421	177,235	172,356	177,853	176,087	168,100	173,706	179,507	185,511	191,723	186,002	192,418	199,061	205,936
	Direct Access	(19,318)	(22,537)	(21,503)	(22,924)	(25,093)	(26,970)	(28,397)	(30,256)	(30,982)	(33,071)	(34,966)	(35,791)	(37,077)	(38,410)	(39,792)	(41,223)	(42,264)	(43,796)	(45,384)	(47,030)
	Total Revenues	$ 638,044	$ 608,231	$ 617,859	$ 636,895	$ 653,072	$ 669,886	$ 663,979	$ 682,164	$ 663,527	$ 684,255	$ 675,895	$ 645,072	$ 667,130	$ 689,961	$ 713,592	$ 738,051	$ 716,174	$ 741,456	$ 767,630	$ 794,730
	EXPENSES ($000)																				
	Power Supply (@market prices)	146,291	172,443	163,715	175,178	192,832	208,098	219,661	234,771	247,298	264,355	279,822	289,968	300,483	311,378	322,669	334,369	346,493	359,057	372,076	385,567
	Public Purpose Programs	18,735	17,977	18,222	18,805	19,328	19,860	19,733	20,304	19,794	20,444	20,260	19,405	20,070	20,759	21,471	22,209	21,615	22,380	23,171	23,990
	DWR Energy/Bond Costs	131,662	134,295	136,981	139,035	140,426	141,830	143,248	144.681	73,064	73,794	74,532	37,639	38,015	38,395	38,779	39,167	-	-	-	-
	Nuclear Decomissioning	1,847	1,884	1,922	1,951	1,970	1,990	2,010	2,030	2,050	2,071	2,091	1,056	1,067	1,077	1,088	1,099	-	-	-	-
	Post transition period CTC	45,535	46,445	47,374	48,085	48,566	49,051	49,542	50,037	50,538	51,043	51,553	26,034	26,295	26,558	26,823	27,092	-	-	-	-
	FTA	23,431	23,900	24,378	24,743	24,991	25,241	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Operations and Maintenance	31,404	32,032	32,672	33,958	35,121	36,324	37,567	38,854	40,223	41,641	43,109	44,629	46,202	47,830	49,516	51,262	53,069	54,940	56,876	58,881
	Transmission ISO (TAC, GMT, Congestion / Ancill	21,944	25,867	24,557	26,277	28,925	31,215	32,949	35,216	37,095	39,653	41,973	43,495	45,072	46,707	48,400	50,155	51,974	53,858	55,811	57,835
4	Other Operations Cost	29,258	29,843	30,440	31,638	32,722	33,842	35,001	36,199	37,475	38,796	40,164	41,580	43,045	44,563	46,133	47,760	49,443	51,186	52,990	54,858
	Direct Access	(19,318)	(22,537)	(21,503)	(22,924)	(25,093)	(26,970)	(28,397)	(30,256)	(30,982)	(33,071)	(34,966)	(35,791)	(37,077)	(38,410)	(39,792)	(41,223)	(42,264)	(43,796)	(45,384)	(47,030)
	Total Expenses	$ 430,788	$ 462,149	$ 458,759	$ 476,747	$ 499,787	$ 520,480	$ 511,314	$ 531,836	$ 476,554	$ 498,727	$ 518,539	$ 468,015	$ 483,171	$ 498,856	$ 515,089	$ 531,889	$ 480,330	$ 497,624	$ 515,540	$ 534,102
	Net Revenues ($000)	$ 207,256	$ 146,083	$ 159,100	$ 160,148	$ 153,285	$ 149,406	$ 152,665	$ 150,328	$ 186,973	$ 185,528	$ 157,358	$ 177,057	$ 183,959	$ 191,105	$ 198,503	$ 206,162	$ 235,844	$ 243,832	$ 252,090	$ 260,628
5	**Municipal Margin**	$ 12,183	$ 12,426	$ 12,675	$ 12,865	$ 12,994	$ 13,123	$ 13,255	$ 13,387	$ 13,521	$ 13,656	$ 13,793	$ 13,931	$ 14,070	$ 14,211	$ 14,353	$ 14,496	$ 14,641	$ 14,788	$ 14,936	$ 15,085
	DEBT SERVICE ($000)																				
6, 7	Federally Taxable (Principal: 1120000000	$ 83,840	$ 83.840	$ 83,840	$ 83,840	$ 83,840	$ 83,840	$ 83,840	$ 83,840	$ 83.840	$ 83,840	$ 83,840	$ 83,840	$ 83.840	$ 83,840	$ 83,840	$ 83,840	$ 83,840	$ 83,840	$ 83,840	$ 83,840
8	Tax exempt (for NEW CIP and R&R)	$ 2,594	$ 5,149	$ 7,662	$ 10,178	$ 12,694	$ 15,219	$ 17,751	$ 20,285	$ 22,820	$ 25,351	$ 27,873	$ 30,382	$ 32,872	$ 35,337	$ 37,772	$ 40,170	$ 42,524	$ 44,829	$ 47,077	$ 49,261
	Total Debt Service	$ 86,434	$ 88,989	$ 91,502	$ 94,018	$ 96,534	$ 99,059	$ 101,591	$ 104,125	$ 106,660	$ 109,191	$ 111,713	$ 114,222	$ 116,712	$ 119,177	$ 121,612	$ 124,010	$ 126,364	$ 128,669	$ 130,917	$ 133,101
9, 10	**Net Income ($000)**	$ 133,005	$ 69,520	$ 80,273	$ 78,995	$ 69,745	$ 63,471	$ 64,329	$ 59,590	$ 93,834	$ 89,994	$ 59,436	$ 76,766	$ 81,317	$ 86,139	$ 91,244	$ 96,649	$ 124,121	$ 129,951	$ 136,109	$ 142,612
	NPV @ 6.0%	$1,003,021																			
	Assumed Debt ($000)	$ 1,123,818																			
	Average Rates ($/kWh)	$ 0.1401	$ 0.1310	$ 0.1304	$ 0.1325	$ 0.1345	$ 0.1366	$ 0.1340	$ 0.1363	$ 0.1313	$ 0.1341	$ 0.1311	$ 0.1239	$ 0.1269	$ 0.1299	$ 0.1330	$ 0.1362	$ 0.1309	$ 0.1341	$ 0.1375	$ 0.1410
	Average Rate	$0.1333																			
	Average Rates [Breakeven] ($/kWh)	$ 0.1136	$ 0.1187	$ 0.1162	$ 0.1187	$ 0.1228	$ 0.1263	$ 0.1237	$ 0.1271	$ 0.1154	$ 0.1191	$ 0.1223	$ 0.1118	$ 0.1141	$ 0.1164	$ 0.1187	$ 0.1211	$ 0.1109	$ 0.1133	$ 0.1158	$ 0.1183
	Average Breakeven Rate	$0.1181																			
	Percent Rate Savings	18.94%	9.39%	10.94%	10.38%	8.69%	7.52%	7.69%	6.77%	12.10%	11.16%	6.75%	9.74%	10.08%	10.42%	10.78%	11.13%	15.29%	15.53%	15.79%	16.05%
		11.26%																			

1 Rates reflect CPUC Final Decision # 03-12-035 issued 12/18/03 in PG&E Bankruptcy case.
2 Rates reflect predominance of primary & secondary service customers
3 Adjusted for Direct Access Load
4 Includes Customer Service, Lost Franchise Fees, Property Taxes, and A&G.
5 25% @ PG&E Medium Commercial Rate - Margin averages $0.02 / kWh due to assumption that 25 % of municipal load is sold at PG&E rates.
6 Principle include System Purchase, Acquisition Cost, Severance, Financed Reserves.
7 Interest rate @ 6.25% 30 year debt level service
8 Interest rate @ 5.00%, 30 year level debt service assuming 100% of capital additions financed annually.
9 Assuming PG&E rates
10 Available to fund CIP, R&R, to reduce rates, to build reserves, or to transfer to general fund.

Base Case: Expected with Low System Cost

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
CUSTOMERS/LOAD										
Load (MWh)										
Residential	1.362.799	1,390,055	1,417,856	1,439,124	1,453,515	1,468,050	1,482,730	1,497,558	1,512,533	1,527,659
Commercial										
Small	537,941	548,699	559,673	568,069	573,749	579,487	585,282	591,134	597,046	603,016
Medium	1,491,301	1,521,127	1,551,549	1,574,822	1,590,571	1,606,476	1,622,541	1,638,766	1,655,154	1,671,706
Large	1,161,417	1,184,646	1,208,338	1,226,464	1,238,728	1,251,115	1,263,627	1,276,263	1,289,026	1,301,916
Municipal	609,130	621,313	633,739	643,245	649,677	656,174	662,736	669,363	676,057	682,817
Total Load at Meter	5,162,587	5,265,839	5,371,156	5,451,723	5,506,240	5,561,303	5,616,916	5.673,085	5,729,816	5,787,114
Less Direct Access	517,218	527,562	538,113	546,185	551,647	557,163	562,735	568,362	574,046	579,786
Load Served (MWh)	4,645,370	4,738,277	4,833,043	4,905,538	4,954,594	5,004,139	5,054,181	5,104,723	5,155,770	5,207,328
Losses @8.0% (MWh)	371,630	379,062	386,643	392,443	396,367	400,331	404,334	408,378	412,462	416,586
Energy Requirement	5,016,999	5,117,339	5,219.686	5,297,981	5,350,961	5,404,471	5,458,515	5,513,100	5,568,232	5,623,914
Market purchases	5,016.999	5,117,339	5,219,686	5,297,981	5,350,961	5,404,471	5,458,515	5,513,100	5,568,232	5,623,914
PRICES										
Market Electricity ($/MWh)	$ 30 00	$ 34.67	$ 32.27	$ 34.02	$ 37.08	$ 39.62	$ 41.40	$ 43.81	$ 45.69	$ 48.36
DWR Bond Repayment ($/MWh)	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 13.50	$ 13.50
Distribution O&M ($/MWh)	$ 6.08	$ 6.08	$ 6.08	$ 6.23	$ 6.38	$ 6.53	$ 6.69	$ 6.85	$ 7.02	$ 7.20
Transmission ($/MWh)	$ 4.50	$ 5.20	$ 4.84	$ 5.10	$ 5.56	$ 5.94	$ 6.21	$ 6.57	$ 6.85	$ 7.25
1 Rates ($/kWh)										
Residential	$ 0.1336	$ 0.1257	$ 0.1248	$ 0.1268	$ 0.1290	$ 0.1312	$ 0.1244	$ 0.1268	$ 0.1215	$ 0.1244
2 Commercial / Industrial										
Small	$ 0.1811	$ 0.1703	$ 0.1695	$ 0.1726	$ 0.1759	$ 0.1792	$ 0.1728	$ 0.1764	$ 0.1724	$ 0.1765
Medium	$ 0.1470	$ 0.1383	$ 0.1374	$ 0.1398	$ 0.1422	$ 0.1447	$ 0.1444	$ 0.1471	$ 0.1422	$ 0.1454
Large	$ 0.1366	$ 0.1285	$ 0.1277	$ 0.1297	$ 0.1320	$ 0.1342	$ 0.1364	$ 0.1389	$ 0.1337	$ 0.1366
Direct Access Average Credit ($/MWh)	$ 37.35	$ 42.72	$ 39.96	$ 41.97	$ 45.49	$ 48.41	$ 50.46	$ 53.23	$ 53.97	$ 57.04
3 **REVENUES ($000)**										
Residential	$ 182,070	$ 174,745	$ 176,986	$ 182,543	$ 187,523	$ 192,588	$ 184,506	$ 189,861	$ 183,835	$ 189,976
Commercial / Industrial										
Small	97.421	93,425	94,886	98,065	100,921	103,841	101,136	104,259	102,925	106,432
Medium	219,221	210,342	213,245	220,096	226.242	232,505	234,313	241,065	235,392	243,064
Large	158,650	152,257	154,245	159,115	163.480	167,923	172,421	177,235	172,356	177,853
Direct Access	(19,318)	(22,537)	(21,503)	(22,924)	(25.093)	(26,970)	(28,397)	(30,256)	(30,982)	(33,071)
Total Revenues	$ 638,044	$ 608,231	$ 617,859	$ 636,895	$ 653,072	$ 669,886	$ 663,979	$ 682,164	$ 663,527	$ 684,255
EXPENSES ($000)										
Power Supply (@market prices)	146.291	172,443	163.715	175,178	192,832	208,098	219,661	234,771	247,298	264,355
Public Purpose Programs	18,735	17,977	18.222	18.805	19,328	19,860	19.733	20,304	19,794	20,444
DWR Energy/Bond Costs	131,662	134,295	136,981	139,035	140,426	141,830	143,248	144,681	73,064	73,794
Nuclear Decomissioning	1,847	1,884	1,922	1,951	1,970	1,990	2,010	2,030	2,050	2,071
Post transition period CTC	45,535	46,445	47,374	48.085	48,566	49,051	49,542	50,037	50,538	51,043
FTA	23,431	23,900	24,378	24,743	24,991	25,241	-	-	-	-
Operations and Maintenance	31,404	32.032	32,672	33,958	35,121	36,324	37,567	38,854	40,223	41,641
Transmission ISO (TAC, GMT, Congestion / Ancill	21,944	25.867	24,557	26,277	28,925	31,215	32.949	35,216	37,095	39,653
4 Other Operations Cost	29,258	29,843	30,440	31,638	32,722	33,842	35,001	36,199	37,475	38,796
Direct Access	(19.318)	(22,537)	(21,503)	(22,924)	(25,093)	(26,970)	(28,397)	(30,256)	(30.982)	(33,071)
Total Expenses	$ 430,788	$ 462,149	$ 458,759	$ 476,747	$ 499,787	$ 520,480	$ 511,314	$ 531,836	$ 476,554	$ 498,727
Net Revenues ($000)	$ 207,256	$ 146,083	$ 159,100	$ 160,148	$ 153,285	$ 149,406	$ 152,665	$ 150,328	$ 186,973	$ 185,528
5 **Municipal Margin**	$ 12,183	$ 12,426	$ 12,675	$ 12,865	$ 12,994	$ 13,123	$ 13,255	$ 13,387	$ 13,521	$ 13,656
DEBT SERVICE ($000)										
6, 7 Federally Taxable (Principal: 720000000	$ 53,861	$ 53,861	$ 53,861	$ 53,861	$ 53,861	$ 53,861	$ 53,861	$ 53,861	$ 53,861	$ 53,861
8 Tax exempt (for NEW CIP and R&R)	$ 2,594	$ 5.149	$ 7,662	$ 10,178	$ 12,694	$ 15,219	$ 17,751	$ 20,285	$ 22,820	$ 25,351
Total Debt Service	$ 56.455	$ 59,010	$ 61,522	$ 64,038	$ 66,554	$ 69,080	$ 71,612	$ 74,146	$ 76,680	$ 79,211
9 ,10 **Net Income ($000)**	$ 162,984	$ 99,499	$ 110,252	$ 108,975	$ 99,724	$ 93,450	$ 94,308	$ 89,570	$ 123,814	$ 119,973
NPV @ 6.0%	$1,346.881									
Assumed Debt ($000)	$ 721,966									
Average Rates ($/kWh)	$ 0.1401	$ 0.1310	$ 0.1304	$ 0.1325	$ 0.1345	$ 0.1366	$ 0.1340	$ 0.1363	$ 0.1313	$ 0.1341
Average Rate	$0.1333									
Average Rates [Breakeven] ($/kWh)	$ 0.1070	$ 0.1122	$ 0.1098	$ 0.1125	$ 0.1166	$ 0.1202	$ 0.1177	$ 0.1211	$ 0.1095	$ 0.1132
Average Breakeven Rate	$0.1123									
Percent Rate Savings	23.63%	14.32%	15.79%	15.09%	13.28%	11.99%	12.21%	11.17%	16.62%	15.54%
	15.66%									

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
CUSTOMERS/LOAD										
Load (MWh)										
Residential	1,542,935	1,558,365	1,573,948	1.589,688	1,605,585	1,621,640	1,637,857	1,654,235	1,670,778	1,687,486
Commercial										
Small	609.046	615,137	621,288	627,501	633,776	640,114	646,515	652,980	659,510	666,105
Medium	1,688,423	1,705.307	1,722,360	1,739,584	1,756,979	1,774,549	1,792,295	1,810.218	1,828,320	1.846.603
Large	1,314,935	1,328,084	1,341,365	1,354,779	1,368,327	1,382,010	1,395,830	1,409,788	1,423,886	1,438,125
Municipal	689,646	696,542	703,508	710,543	717,648	724,824	732,073	739,393	746,787	754,255
Total Load at Meter	5,844.985	5,903,435	5,962,469	6,022,094	6,082,315	6,143,138	6,204,569	8,266,615	6,329,281	6,392,574
Less Direct Access	585,584	591,440	597,354	603,328	609,361	615,455	621,609	627,825	634,104	640,445
Load Served (MWh)	5,259,401	5,311,995	5,365,115	5,418,766	5,472,954	5,527,683	5,582,960	5,638,790	5,695,178	5,752,129
Losses @8.0% (MWh)	420,752	424,960	429,209	433,501	437,836	442,215	446,637	451,103	455,614	460,170
Energy Requirement	5,680,153	5,736,954	5,794,324	5,852,267	5,910,790	5,969,898	6,029,597	6,089.893	6,150,792	6,212,300
Market purchases	5,680,153	5,736,954	5,794,324	5,852,267	5,910,790	5,969.898	6,029,597	6,089,893	6,150,792	6,212,300
PRICES										
Market Electricity ($/MWh)	$ 50.68	$ 52.00	$ 53.35	$ 54.74	$ 56.16	$ 57.62	$ 59.12	$ 60.66	$ 62.24	$ 63.86
DWR Bond Repayment ($/MWh)	$ 13.50	$ 6.75	$ 6.75	$ 6.75	$ 6.75	$ 6.75	$ -	$ -	$ -	$ -
Distribution O&M ($/MWh)	$ 7 38	$ 7.56	$ 7.75	$ 7.94	$ 8.14	$ 8.34	$ 8.55	$ 8.77	$ 8.99	$ 9.21
Transmission ($/MWh)	$ 7.60	$ 7.80	$ 8.00	$ 8.21	$ 8 42	$ 8.64	$ 8.87	$ 9.10	$ 9.34	$ 9.58
1 Rates ($/kWh)										
Residential	$ 0.1221	$ 0.1146	$ 0.1175	$ 0.1204	$ 0.1234	$ 0.1265	$ 0.1209	$ 0.1240	$ 0.1272	$ 0.1305
2 Commercial / Industrial										
Small	$ 0.1734	$ 0.1673	$ 0.1715	$ 0.1757	$ 0.1801	$ 0.1846	$ 0.1805	$ 0.1852	$ 0.1899	$ 0.1948
Medium	$ 0.1426	$ 0.1356	$ 0.1388	$ 0,1421	$ 0.1455	$ 0.1489	$ 0.1438	$ 0.1474	$ 0.1510	$ 0.1548
Large	$ 0.1339	$ 0.1266	$ 0.1295	$ 0.1325	$ 0.1356	$ 0.1387	$ 0.1333	$ 0.1365	$ 0.1398	$ 0.1432
Direct Access Average Credit ($/MWh)	$ 59.71	$ 60.51	$ 62.07	$ 63.66	$ 65.30	$ 66.98	$ 67.99	$ 69.76	$ 71.57	$ 73.43
3 **REVENUES ($000)**										
Residential	$ 188,348	$ 178,666	$ 184,926	$ 191,407	$ 198,116	$ 205,063	$ 197,998	$ 205,167	$ 212,592	$ 220,281
Commercial / Industrial										
Small	105,607	102,899	106,523	110,275	114,160	118,182	116,718	120,920	125,271	129,776
Medium	240,819	231,197	239,052	247.183	255,597	264,307	257,720	266,747	276.092	285,767
Large	176,087	168,100	173,706	179.507	185,511	191,723	186,002	192,418	199,061	205,936
Direct Access	(34,966)	(35,791)	(37,077)	(38,410)	(39.792)	(41,223)	(42,264)	(43,796)	(45,384)	(47,030)
Total Revenues	$ 675,895	$ 645,072	$ 667,130	$ 689,961	$ 713,592	$ 738,051	$ 716,174	$ 741,456	$ 767,630	$ 794,730
EXPENSES ($000)										
Power Supply (@market prices)	279,822	289.968	300,483	311,378	322,669	334,369	346,493	359,057	372,076	385,567
Public Purpose Programs	20,260	19,405	20,070	20,759	21,471	22,209	21,615	22,380	23,171	23,990
DWR Energy/Bond Costs	74,532	37,639	38,015	38,395	38,779	39,167	-	-	-	-
Nuclear Decomissioning	2,091	1.056	1,067	1,077	1,088	1,099	-	-	-	-
Post transition period CTC	51,553	26,034	26,295	26,558	26,823	27,092	-	-	-	-
FTA	-	-	-	-	-	-	-	-	-	-
Operations and Maintenance	43,109	44,629	46,202	47,830	49,516	51,262	53.069	54,940	56,876	58,881
Transmission ISO (TAC, GMT, Congestion / Ancill	41,973	43,495	45,072	46,707	48,400	50,155	51,974	53,858	55,811	57,835
4 Other Operations Cost	40,164	41,580	43,045	44,563	46,133	47,760	49,443	51,186	52,990	54,858
Direct Access	(34,966)	(35,791)	(37,077)	(38,410)	(39,792)	(41,223)	(42,264)	(43,796)	(45,384)	(47,030)
Total Expenses	$ 518,639	$ 468,015	$ 483,171	$ 498,856	$ 515,089	$ 531,889	$ 480,330	$ 497,624	$ 515,540	$ 534,102
Net Revenues ($000)	$ 157,356	$ 177,057	$ 183,959	$ 191,105	$ 198,503	$ 206,162	$ 235,844	$ 243,832	$ 252,090	$ 260,628
5 **Municipal Margin**	$ 13,793	$ 13,931	$ 14,070	$ 14,211	$ 14,353	$ 14,496	$ 14,641	$ 14,788	$ 14,936	$ 15,085
DEBT SERVICE ($000)										
6, 7 Federally Taxable (Principal: 720000000	$ 53,861	$ 53.861	$ 53,861	$ 53,861	$ 53,861	$ 53,861	$ 53,861	$ 53,861	$ 53,861	$ 53,861
8 Tax exempt (for NEW CIP and R&R)	$ 27,873	$ 30,382	$ 32,872	$ 35,337	$ 37,772	$ 40,170	$ 42,524	$ 44,829	$ 47,077	$ 49,261
Total Debt Service	$ 81,734	$ 84,243	$ 86.732	$ 89,198	$ 91,632	$ 94,030	$ 96,385	$ 98,690	$ 100,938	$ 103,122
9 ,10 **Net Income ($000)**	$ 89,416	$ 106,745	$ 111,297	$ 116,118	$ 121,223	$ 126,628	$ 154,100	$ 159,930	$ 166,088	$ 172,591
Average Rates ($/kWh)	$ 0.1311	$ 0.1239	$ 0.1269	$ 0.1299	$ 0.1330	$ 0.1362	$ 0.1309	$ 0.1341	$ 0.1375	$ 0.1410
Average Rates [Breakeven] ($/kWh)	$ 0.1164	$ 0.1061	$ 0.1084	$ 0.1107	$ 0.1131	$ 0.1155	$ 0.1054	$ 0.1079	$ 0.1104	$ 0.1130
Percent Rate Savings	11.19%	14.39%	14.57%	14.77%	14.98%	15.19%	19.47%	19.58%	19 69%	19.82%

1 Rates reflect CPUC Final Decision # 03-12-035 issued 12/18/03 in PG&E Bankruptcy case.
2 Rates reflect predominance of primary & secondary service customers
3 Adjusted for Direct Access Load
4 Includes Customer Service, Lost Franchise Fees, Property Taxes, and A&G.
5 25% @ PG&E Medium Commercial Rate - Margin averages $0.02 / kWh due to assumption that 25 % of municipal load is sold at PG&E rates.
6 Principle include System Purchase, Acquisition Cost, Severance, Financed Reserves.
7 Interest rate @ 6.25% 30 year debt level service
8 Interest rate @ 5.00%, 30 year level debt service assuming 100% of capitol additions financed annually.
9 Assuming PG&E rates
10 Available to fund CIP, R&R, to reduce rates, to build reserves, or to transfer to general fund.

Base Case: Expected with High System Cost

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	CUSTOMERS/LOAD										
	Load (MWh)										
	Residential	1,362,799	1,390,055	1,417,858	1,439,124	1,453,515	1,488,050	1,482,730	1,497,558	1,512,533	1,527,859
	Commercial										
	Small	537,941	548,699	559,873	568,069	573,749	579,487	585,282	591,134	587,046	603,018
	Medium	1,491,301	1,521,127	1,551,549	1,574,822	1,590,571	1,606,478	1,622,541	1,838,766	1,655,154	1,671,706
	Large	1,181,417	1,184,648	1,208,338	1,228,464	1,238,728	1,251,115	1,263,627	1,276,263	1,289,026	1,301,916
	Municipal	609,130	821,313	633,739	643,245	649,677	856,174	662,736	869,363	676,057	682,817
	Total Load at Meter	5,162,587	5,265,839	5,371,158	5,451,723	5,506,240	5,581,303	5,616,916	5,673,085	5,729,816	5,787,114
	Less Direct Access	517,218	527,562	538,113	546,185	551,647	557,163	562,735	568,362	574,046	579,786
	Load Served (MWh)	4,645,370	4,738,277	4,833,043	4,905,538	4,954,594	5,004,139	5,054,181	5,104,723	5,155,770	5,207,328
	Losses @8.0% (MWh)	371,630	379,062	386,643	392,443	396,367	400,331	404,334	408,378	412,462	416,588
	Energy Requirement	5,016,999	5,117,339	5,219,688	5,297,981	5,350,961	5,404,471	5,458,515	5,513,100	5,568,232	5,623,914
	Market purchases	5,016,999	5,117,339	5,219,686	5,297,981	5,350,961	5,404,471	5,458,515	5,513,100	5,568,232	5,623,914
	PRICES										
	Market Electricity ($/MWh)	$ 30.00	$ 34.67	$ 32.27	$ 34.02	$ 37.08	$ 39.62	$ 41.40	$ 43.81	$ 45.69	$ 48.36
	DWR Bond Repayment ($/MWh)	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 13.50	$ 13.50
	Distribution O&M ($/MWh)	$ 6.08	$ 8.08	$ 6.08	$ 6.23	$ 6.38	$ 6.53	$ 8.69	$ 6.85	$ 7.02	$ 7.20
	Transmission ($/MWh)	$ 4.50	$ 5.20	$ 4.84	$ 5.10	$ 5.56	$ 5.94	$ 8.21	$ 6.57	$ 6.85	$ 7.25
1	Rates ($/kWh)										
	Residential	$ 0.1336	$ 0.1257	$ 0.1248	$ 0.1268	$ 0.1290	$ 0.1312	$ 0.1244	$ 0.1268	$ 0.1215	$ 0.1244
2	Commercial / Industrial										
	Small	$ 0.1811	$ 0.1703	$ 0.1695	$ 0.1726	$ 0.1759	$ 0.1792	$ 0.1728	$ 0.1764	$ 0.1724	$ 0.1765
	Medium	$ 0.1470	$ 0.1383	$ 0.1374	$ 0.1398	$ 0.1422	$ 0.1447	$ 0.1444	$ 0.1471	$ 0.1422	$ 0.1454
	Large	$ 0.1366	$ 0.1285	$ 0.1277	$ 0.1297	$ 0.1320	$ 0.1342	$ 0.1364	$ 0.1389	$ 0.1337	$ 0.1366
	Direct Access Average Credit ($/MWh)	$ 37.35	$ 42.72	$ 39.96	$ 41.97	$ 45.49	$ 48.41	$ 50.46	$ 53.23	$ 53.87	$ 57.04
3	**REVENUES ($000)**										
	Residential	$ 182,070	$ 174,745	$ 178,986	$ 182,543	$ 187,523	$ 192,588	$ 184,508	$ 189,861	$ 183,835	$ 189,976
	Commercial / Industrial										
	Small	97,421	93,425	94,888	98,065	100,821	103,841	101,136	104,259	102,925	106,432
	Medium	219,221	210,342	213,245	220,096	226,242	232,505	234,313	241,065	235,392	243,064
	Large	158,650	152,257	154,245	159,115	163,480	187,923	172,421	177,235	172,356	177,853
	Direct Access	(19,318)	(22,537)	(21,503)	(22,924)	(25,093)	(26,970)	(28,397)	(30,256)	(30,982)	(33,071)
	Total Revenues	$ 638,044	$ 608,231	$ 617,859	$ 636,895	$ 653,072	$ 669,888	$ 663,979	$ 882,164	$ 663,527	$ 684,255
	EXPENSES ($000)										
	Power Supply (@market prices)	146,291	172,443	163,715	175,178	192,832	208,098	219,661	234,771	247,298	264,355
	Public Purpose Programs	18,735	17,977	18,222	18,805	19,328	19,860	19,733	20,304	19,794	20,444
	DWR Energy/Bond Costs	131,662	134,295	136,981	139,035	140,426	141,830	143,248	144,681	73,064	73,784
	Nuclear Decomissioning	1,847	1,884	1,922	1,951	1,970	1,990	2,010	2,030	2,050	2,071
	Post transition period CTC	45,535	46,445	47,374	48,085	48,566	49,051	49,542	50,037	50,538	51,043
	FTA	23,431	23,900	24,378	24,743	24,991	25.241	-	-	-	-
	Operations and Maintenance	31,404	32,032	32,672	33,958	35,121	36,324	37,567	38,854	40,223	41,641
	Transmission ISO (TAC, GMT, Congestion / Ancill	21,944	25,867	24,557	26,277	28,925	31,215	32,949	35,216	37,095	39,653
4	Other Operations Cost	29,258	29,843	30,440	31,638	32,722	33,842	35,001	36,199	37,475	38,796
	Direct Access	(19,318)	(22,537)	(21,503)	(22,924)	(25,093)	(26,970)	(28,397)	(30,256)	(30,982)	(33,071)
	Total Expenses	$ 430,788	$ 462,149	$ 458,759	$ 476,747	$ 499,787	$ 520,480	$ 511,314	$ 531,838	$ 476,554	$ 498,727
	Net Revenues ($000)	$ 207,256	$ 146,083	$ 159,100	$ 160,148	$ 153,285	$ 149,408	$ 152,665	$ 150,328	$ 186,973	$ 185,528
5	**Municipal Margin**	$ 12,183	$ 12,426	$ 12,675	$ 12,865	$ 12,994	$ 13,123	$ 13,255	$ 13,387	$ 13,521	$ 13,656
	DEBT SERVICE ($000)										
6, 7	Federally Taxable (Principal: 1520000000	$ 118,586	$ 116,586	$ 116,588	$ 116,586	$ 116,586	$ 116,586	$ 116,586	$ 116,588	$ 116,586	$ 118,588
8	Tax exempt (for NEW CIP and R&R)	$ 2,594	$ 5,149	$ 7,662	$ 10,178	$ 12,694	$ 15,219	$ 17,751	$ 20,285	$ 22,820	$ 25,351
	Total Debt Service	$ 119,180	$ 121,735	$ 124,248	$ 126,764	$ 129,280	$ 131,806	$ 134,337	$ 136,871	$ 139,406	$ 141,937
9, 10	**Net Income ($000)**	$ 100,259	$ 36,774	$ 47,527	$ 46,249	$ 36,999	$ 30,724	$ 31,582	$ 26,844	$ 61,088	$ 57,247
	NPV @ 6.0%	$627,424									
	Assumed Debt ($000)	$ 1,562,759									
	Average Rates ($/kWh)	$ 0.1401	$ 0.1310	$ 0.1304	$ 0.1325	$ 0.1345	$ 0.1366	$ 0.1340	$ 0.1363	$ 0.1313	$ 0.1341
	Average Rate	$0.1333									
	Average Rates [Breakeven] ($/kWh)	$ 0.1208	$ 0.1257	$ 0.1231	$ 0.1255	$ 0.1295	$ 0.1330	$ 0.1303	$ 0,1336	$ 0.1219	$ 0.1255
	Average Breakeven Rate	$0.1245									
	Percent Rate Savings	13.80%	4.00%	5 64%	5.24%	3.68%	2.63%	2.76%	1.97%	7.17%	8.37%
		6.44%									

		2013	2014	2015	2018	2017	2018	2019	2020	2021	2022
	CUSTOMERS/LOAD										
	Load (MWh)										
	Residential	1,542,935	1,558,365	1,573,848	1,589,688	1,605,585	1,621,640	1,637,857	1,654,235	1,870,778	1,887,488
	Commercial										
	Small	609,046	615,137	621,288	827,501	633,776	640,114	646,515	652,980	659,510	666,105
	Medium	1,688,423	1,705,307	1,722,360	1,739,584	1,756,979	1,774,549	1,792,295	1,810,218	1,828,320	1,846,603
	Large	1,314,935	1,328,084	1,341,365	1,354,779	1,368,327	1,382,010	1,395,830	1,408,788	1,423,886	1,438,125
	Municipal	689,646	696,542	703,508	710,543	717,648	724,824	732,073	739,393	746,787	754,255
	Total Load at Meter	5,844,985	5,903,435	5,962,469	6,022,094	6,082,315	8,143,138	6,204,569	8,266,815	6,329,281	8,392,574
	Less Direct Access	585,584	591,440	597,354	603,328	609,381	615,455	621,609	627,825	634,104	640,445
	Load Served (MWh)	5,259,401	5,311,995	5,365,115	5,418,766	5,472,954	5,527,683	5,582,960	5,638,790	5,885,178	6,752,129
	Losses @8.0% (MWh)	420,752	424,960	429,209	433,501	437,836	442,215	446,637	451,103	455,814	460,170
	Energy Requirement	5,680,153	5,736,954	5,794,324	5,852,267	5,910,780	5,969,898	8,029,597	6,089,893	6,150,792	6,212,300
	Market purchases	5,880,153	5,738,954	5,794,324	5,852,267	5,810,790	5,969,898	8,029,597	8,089,893	8,150,792	8,212,300
	PRICES										
	Market Electricity ($/MWh)	$ 50.68	$ 52.00	$ 53.35	$ 64.74	$ 56.16	$ 57.62	$ 59.12	$ 60.68	$ 62.24	$ 63.86
	DWR Bond Repayment ($/MWh)	$ 13.50	$ 6.75	$ 6 75	$ 8.75	$ 8.75	$ 8.75	$ -	$ -	$ -	$ -
	Distribution O&M ($/MWh)	$ 7.38	$ 7.56	$ 7.75	$ 7.94	$ 8.14	$ 8.34	$ 8.55	$ 8.77	$ 8.99	$ 9.21
	Transmission ($/MWh)	$ 7.60	$ 7.80	$ 8.00	$ 8.21	$ 8.42	$ 8.64	$ 8.87	$ 9.10	$ 9.34	$ 9.58
1	Rates ($/kWh)										
	Residential	$ 0.1221	$ 0.1146	$ 0.1175	$ 0.1204	$ 0.1234	$ 0.1265	$ 0.1209	$ 0.1240	$ 0.1272	$ 0.1305
2	Commercial / Industrial										
	Small	$ 0.1734	$ 0.1873	$ 0.1715	$ 0.1757	$ 0.1801	$ 0.1848	$ 0.1805	$ 0.1852	$ 0.1899	$ 0.1948
	Medium	$ 0.1426	$ 0.1356	$ 0.1388	$ 0.1421	$ 0.1455	$ 0.1489	$ 0.1438	$ 0.1474	$ 0.1510	$ 0.1548
	Large	$ 0.1339	$ 0.1268	$ 0.1295	$ 0.1325	$ 0.1356	$ 0.1387	$ 0.1333	$ 0.1385	$ 0.1398	$ 0.1432
	Direct Access Average Credit ($/MWh)	$ 59.71	$ 60.51	$ 62.07	$ 63.66	$ 65 30	$ 66.98	$ 87.99	$ 69.78	$ 71.57	$ 73.43
3	**REVENUES ($000)**										
	Residential	$ 188,348	$ 178,666	$ 184,928	$ 191,407	$ 198,118	$ 205,063	$ 197,998	$ 205,187	$ 212,592	$ 220,281
	Commercial / Industrial										
	Small	105,607	102,899	106,523	110,275	114,160	118,182	118,718	120,820	125,271	129,778
	Medium	240,819	231,197	239,052	247,183	255,597	264,307	257,720	266,747	278,092	285,787
	Large	176,087	188,100	173,706	179,507	185,511	191,723	186,002	192,418	199,061	205,936
	Direct Access	(34,966)	(35,791)	(37,077)	(38,410)	(39,782)	(41,223)	(42,264)	(43,796)	(45,384)	(47,030)
	Total Revenues	$ 675,895	$ 645,072	$ 667,130	$ 689,981	$ 713,592	$ 738,051	$ 716,174	$ 741,458	$ 767,630	$ 794,730
	EXPENSES ($000)										
	Power Supply (@market prices)	279,822	289,968	300,483	311,378	322,669	334,369	346,493	359,057	372,078	385,567
	Public Purpose Programs	20,260	19,405	20,070	20,759	21,471	22,209	21,615	22,380	23,171	23,990
	DWR Energy/Bond Costs	74,532	37,639	38,015	38,395	38,779	39,167	-	-	-	-
	Nuclear Decomissioning	2,091	1,056	1,067	1,077	1,088	1,099	-	-	-	-
	Post transition period CTC	51,553	26,034	26,285	26,558	26,823	27,092	-	-	-	-
	FTA	-	-	-	-	-	-	-	-	-	-
	Operations and Maintenance	43,109	44,629	46,202	47,830	49,516	51,262	53,069	54,940	56,876	58,881
	Transmission ISO (TAC, GMT, Congestion / Ancill	41,973	43,495	45,072	46,707	48,400	50,155	51,974	53,858	55,811	57,835
4	Other Operations Cost	40,164	41,580	43,045	44,563	46,133	47,760	49,443	51,186	52,990	54,858
	Direct Access	(34,966)	(35,791)	(37,077)	(38,410)	(39,792)	(41,223)	(42,264)	(43,796)	(45,384)	(47,030)
	Total Expenses	$ 518,539	$ 468,015	$ 483,171	$ 498,856	$ 515,089	$ 531,889	$ 480,330	$ 497,624	$ 515,540	$ 534,102
	Net Revenues ($000)	$ 167,356	$ 177,057	$ 183,959	$ 191,105	$ 198,503	$ 206,162	$ 235,844	$ 243,832	$ 252,090	$ 280,828
5	**Municipal Margin**	$ 13,793	$ 13,931	$ 14,070	$ 14,211	$ 14,353	$ 14,498	$ 14,641	$ 14,788	$ 14,936	$ 15,085
	DEBT SERVICE ($000)										
6, 7	Federally Taxable (Principal: 1520000000	$ 116,586	$ 116,588	$ 116,586	$ 116,586	$ 118,586	$ 116,586	$ 118,586	$ 116,588	$ 118,588	$ 118,586
8	Tax exempt (for NEW CIP and R&R)	$ 27,873	$ 30,382	$ 32,872	$ 35,337	$ 37,772	$ 40,170	$ 42,524	$ 44,829	$ 47,077	$ 49,261
	Total Debt Service	$ 144,459	$ 146,968	$ 149,458	$ 151,923	$ 154,358	$ 156,756	$ 159,110	$ 161,415	$ 163,663	$ 165,847
9, 10	**Net Income ($000)**	$ 26,690	$ 44,019	$ 48,571	$ 53,392	$ 58,498	$ 63,902	$ 91,375	$ 97,204	$ 103,363	$ 109,868
	Average Rates ($/kWh)	$ 0.1311	$ 0.1239	$ 0.1269	$ 0.1299	$ 0.1330	$ 0.1362	$ 0.1309	$ 0.1341	$ 0.1375	$ 0.1410
	Average Rates [Breakeven] ($/kWh)	$ 0.1286	$ 0.1181	$ 0.1203	$ 0.1225	$ 0.1248	$ 0.1271	$ 0.1168	$ 0.1192	$ 0.1217	$ 0.1241
	Percent Rate Savings	1.91%	4.66%	5.17%	5.68%	6.19%	6.69%	10.71%	11.12%	11.52%	11.93%

1 Rates reflect CPUC Final Decision # 03-12-035 Issued 12/18/03 in PG&E Bankruptcy case.
2 Rates reflect predominance of primary & secondary service customers
3 Adjusted for Direct Access Load
4 Includes Customer Service, Lost Franchise Fees, Property Taxes, and A&G.
5 25% @ PG&E Medium Commercial Rate - Margin averages $0.02 / kWh due to assumption that 25 % of municipal load is sold at PG&E rates.
6 Principle include System Purchase, Acquisition Cost, Severance, Financed Reserves.
7 Interest rate @ 8 25% 30 year debt level service
8 Interest rate @ 5.00%, 30 year level debt service assuming 100% of capital additions financed annually.
9 Assuming PG&E rates
10 Available to fund CIP, R&R, to reduce rates, to build reserves, or to transfer to general fund.

Best Case / Scenario 1

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	CUSTOMERS/LOAD										
	Load (MWh)										
	Residential	1,388,462	1,473,203	1,513,262	1,531,750	1,550,239	1,568,728	1,587,217	1,605,706	1,624,195	1,642,683
	Commercial										
	Small	548,071	581,521	597,333	604,631	611,929	619,228	626,526	633,824	641,122	648,420
	Medium	1,519,384	1,612,115	1,655,951	1,676,183	1,696,415	1,716,648	1,736,880	1,757,112	1,777,344	1,797,576
	Large	1,183,288	1,255,507	1,289,646	1,305,403	1,321,160	1,338,916	1,352,673	1,368,430	1,384,186	1,399,943
	Municipal	609,130	646,306	663,881	671,992	680,103	688,214	696,325	704,437	712,548	720,659
	Total Load at Meter	5,248,335	5,568,651	5,720,073	5,789,960	5,859,847	5,929,734	5,999,621	6,069,508	6,139,395	6,209,282
	Less Direct Access	526,957	559,119	574,322	581,339	588,356	595,373	602,390	609,407	616,424	623,441
	Load Served (MWh)	4,721,378	5,009,532	5,145,751	5,208,621	5,271,491	5,334,361	5,397,231	5,460,101	5,522,971	5,585,841
	Losses @8.0% (MWh)	377,710	400,763	411,660	416,690	421,719	426,749	431,778	436,808	441,838	446,867
	Energy Requirement	5,099,088	5,410,295	5,557,411	5,625,310	5,693,210	5,761,110	5,829,009	5,896,909	5,964,809	6,032,708
	Market purchases	5,099,088	5,410,295	5,557,411	5,625,310	5,693,210	5,761,110	5,829,009	5,896,909	5,964,809	6,032,708
	PRICES										
	Market Electricity ($/MWh)	24.00	27.74	25.82	27.22	29.66	31.89	33.12	35.05	36.55	38.69
	DWR Bond Repayment ($/MWh)	27.00	27.00	27.00	27.00	27.00	27.00	27.00	27.00	13.50	13.50
	Distribution O&M ($/MWh)	6.10	6.10	6.10	6.24	6.39	6.55	6.70	6.86	7.04	7.21
	Transmission ($/MWh)	3.60	4.16	3.87	4.08	4.45	4.75	4.97	5.26	5.48	5.80
1	Rates ($/kWh)										
	Residential	0.1336	0.1257	0.1248	0.1268	0.1290	0.1312	0.1244	0.1268	0.1215	0.1244
2	Commercial / Industrial										
	Small	0.1811	0.1703	0.1695	0.1726	0.1759	0.1792	0.1728	0.1764	0.1724	0.1765
	Medium	0.1470	0.1383	0.1374	0.1398	0.1422	0.1447	0.1444	0.1471	0.1422	0.1454
	Large	0.1366	0.1285	0.1277	0.1297	0.1320	0.1342	0.1364	0.1389	0.1337	0.1366
	Direct Access Average Credit ($/MWh)	37.35	42.72	39.96	41.97	45.49	48.41	50.46	53.23	53.97	57.04
3	**REVENUES ($000)**										
	Residential	185,499	185,198	188,895	194,292	200,001	205,795	197,508	203,572	197,406	204,280
	Commercial / Industrial										
	Small	99,256	99,013	101,271	104,376	107,636	110,963	108,263	111,788	110,524	114,446
	Medium	223,349	222,924	227,594	234,262	241,297	248,450	250,825	258,474	252,770	261,366
	Large	161,637	161,364	164,624	169,356	174,359	179,439	184,571	190,034	185,080	191,245
	Direct Access	(19,681)	(23,885)	(22,949)	(24,399)	(26,762)	(28,820)	(30,398)	(32,441)	(33,269)	(35,561)
	Total Revenues	650,059	644,613	659,434	677,888	696,531	715,827	710,769	731,427	712,511	735,775
	EXPENSES ($000)										
	Power Supply (@market prices)	119,236	146,207	139,785	149,163	164,531	177,895	188,112	201,380	212,444	227,408
	Public Purpose Programs	19,088	19,052	19,448	20,015	20,614	21,222	21,123	21,770	21,255	21,983
	DWR Energy/Bond Costs	134,141	142,328	146,198	147,984	149,770	151,557	153,343	155,129	78,458	79,351
	Nuclear Decomissioning	1,882	1,997	2,051	2,076	2,101	2,126	2,151	2,177	2,202	2,227
	Post transition period CTC	46,392	49,223	50,562	51,180	51,797	52,415	53,033	53,651	54,268	54,886
	FTA	23,872	25,329	26,018	26,336	26,654	26,972	-	-	-	-
	Operations and Maintenance	31,995	33,948	34,871	36,144	37,458	38,815	40,215	41,660	43,193	44,777
	Transmission ISO (TAC, GMT, Congestion / Ancill	17,885	21,931	20,968	22,374	24,680	26,684	28,217	30,207	31,867	34,111
4	Other Operations Cost	29,809	31,628	32,488	33,675	34,899	36,163	37,467	38,813	40,242	41,717
	Direct Access	(19,681)	(23,885)	(22,949)	(24,399)	(26,762)	(28,820)	(30,398)	(32,441)	(33,269)	(35,561)
	Total Expenses	404,620	447,758	449,440	464,548	485,743	505,029	493,264	512,346	450,658	470,898
	Net Revenues ($000)	245,440	196,855	209,994	213,340	210,788	210,798	217,505	219,081	261,853	264,877
5	**Municipal Margin**	12,183	12,926	13,278	13,440	13,602	13,764	13,927	14,089	14,251	14,413
	DEBT SERVICE ($000)										
6, 7	Federally Taxable (Principal: 720000000	53,861	53,861	53,861	53,861	53,861	53,861	53,861	53,861	53,861	53,861
8	Tax exempt (for NEW CIP and R&R)	2,643	5,301	7,830	10,336	12,855	15,383	17,916	20,452	22,987	25,519
	Total Debt Service	56,504	59,162	61,691	64,197	66,715	69,244	71,777	74,312	76,848	79,379
9, 10	**Net Income ($000)**	201,119	150,619	161,581	162,583	157,675	155,318	159,655	158,857	199,256	199,911
	NPV @ 6.0%	$2,182,731									
	Assumed Debt ($000)	$ 721,966									
	Average Rates ($/kWh)	0.1401	0.1310	0.1304	0.1325	0.1345	0.1366	0.1340	0.1363	0.1313	0.1341
	Average Rate	$0.1333									
	Average Rates [Breakeven] ($/kWh)	0.0994	0.1030	0.1011	0.1033	0.1067	0.1096	0.1065	0.1093	0.0972	0.1003
	Average Breakeven Rate	$0.0992									
	Percent Rate Savings	29.06%	21.36%	22.49%	22.00%	20.68%	19.77%	20.50%	19.79%	25.97%	25.21%
		25.31%									

		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	CUSTOMERS/LOAD										
	Load (MWh)										
	Residential	1,661,383	1,680,295	1,699,422	1,718,767	1,738,333	1,758,121	1,778,134	1,798,375	1,818,847	1,839,552
	Commercial										
	Small	655,801	663,267	670,817	678,453	686,176	693,987	701,887	709,877	717,958	726,130
	Medium	1,818,039	1,838,734	1,859,665	1,880,835	1,902,245	1,923,899	1,945,799	1,967,949	1,990,351	2,013,008
	Large	1,415,879	1,431,997	1,448,298	1,464,784	1,481,458	1,498,322	1,515,378	1,532,629	1,550,075	1,567,720
	Municipal	728,863	737,159	745,551	754,038	762,621	771,302	780,082	788,962	797,943	807,027
	Total Load at Meter	6,279,965	6,351,452	6,423,753	6,496,877	6,570,833	6,645,631	6,721,281	6,787,792	6,875,174	6,953,437
	Less Direct Access	630,538	637,716	644,975	652,317	659,742	667,253	674,848	682,530	690,300	698,158
	Load Served (MWh)	5,649,427	5,713,736	5,778,778	5,844,560	5,911,091	5,978,379	6,046,433	6,115,262	8,184,874	6,255,279
	Losses @8.0% (MWh)	451,954	457,099	462,302	467,565	472,887	478,270	483,715	489,221	494,790	500,422
	Energy Requirement	6,101,381	6,170,835	6,241,080	6,312,125	6,383,978	6,456,649	6,530,148	6,604,483	6,679,664	8,755,701
	Market purchases	6,101,381	6,170,835	6,241,080	6,312,125	6,383,978	6,456,649	8,530,148	6,604,483	6,679,664	8,755,701
	PRICES										
	Market Electricity ($/MWh)	40.55	41.60	42.68	43.79	44.93	46.10	47.30	48.53	49.79	51.08
	DWR Bond Repayment ($/MWh)	13.50	6.75	6.75	6.75	6.75	6.75	-	-	-	-
	Distribution O&M ($/MWh)	7.39	7.58	7.77	7.96	8.16	8.36	8.57	8.79	9.01	9.23
	Transmission ($/MWh)	6.08	6.24	6.40	6.57	6.74	6.91	7.09	7.28	7.47	7.66
1	Rates ($/kWh)										
	Residential	0.1221	0.1146	0.1175	0.1204	0.1234	0.1265	0.1209	0.1240	0.1272	0.1305
2	Commercial / Industrial										
	Small	0.1734	0.1673	0.1715	0.1757	0.1801	0.1846	0.1805	0.1852	0.1899	0.1948
	Medium	0.1426	0.1356	0.1388	0.1421	0.1455	0.1489	0.1438	0.1474	0.1510	0.1548
	Large	0.1339	0.1266	0.1295	0.1325	0.1356	0.1387	0.1333	0.1365	0.1398	0.1432
	Direct Access Average Credit ($/MWh)	59.71	60.51	62.07	63.66	65.30	66.98	67.99	69.76	71.57	73.43
3	**REVENUES ($000)**										
	Residential	202,808	192,645	199,668	206,948	214,496	222,321	214,956	223,044	231,432	240,131
	Commercial / Industrial										
	Small	113,715	110,950	115,015	119,229	123,598	128,128	126,715	131,456	136,372	141,471
	Medium	259,306	249,286	258,109	267,253	276,730	286,551	279,793	289,989	300,560	311,519
	Large	189,604	181,253	187,554	194,083	200,848	207,859	201,932	209,185	216,702	224,494
	Direct Access	(37,650)	(38,591)	(40,033)	(41,529)	(43,082)	(44,693)	(45,884)	(47,613)	(49,407)	(51,268)
	Total Revenues	727,782	695,544	720,313	745,985	772,591	800,166	777,512	806,062	835,660	866,346
	EXPENSES ($000)										
	Power Supply (@market prices)	241,043	250,125	259,549	269,329	279,477	290,008	300,935	312,274	324,040	336,250
	Public Purpose Programs	21,815	20,923	21,670	22,444	23,247	24,078	23,467	24,330	25,224	26,152
	DWR Energy/Bond Costs	80,254	40,584	41,046	41,513	41,986	42,464	-	-	-	-
	Nuclear Decomissioning	2,252	1,139	1,152	1,165	1,178	1,192	-	-	-	-
	Post transition period CTC	55,511	28,071	28,391	28,714	29,041	29,372	-	-	-	-
	FTA	-	-	-	-	-	-	-	-	-	-
	Operations and Maintenance	46,418	48,121	49,885	51,714	53,610	55,576	57,614	59,727	61,917	64,187
	Transmission ISO (TAC, GMT, Congestion / Ancill	36,156	37,519	38,932	40,399	41,922	43,501	45,140	46,841	48,606	50,438
4	Other Operations Cost	43,247	44,833	46,477	48,181	49,948	51,779	53,678	55,646	57,686	59,802
	Direct Access	(37,650)	(38,591)	(40,033)	(41,529)	(43,082)	(44,693)	(45,884)	(47,613)	(49,407)	(51,268)
	Total Expenses	489,046	432,723	447,069	461,930	477,326	493,277	434,950	451,205	468,067	485,560
	Net Revenues ($000)	238,736	262,821	273,244	284,054	295,265	306,890	342,562	354,857	367,593	380,786
5	**Municipal Margin**	14,577	14,743	14,911	15,081	15,252	15,426	15,602	15,779	15,959	16,141
	DEBT SERVICE ($000)										
6, 7	Federally Taxable (Principal: 720000000	53,861	53,861	53,861	53,861	53,861	53,861	53,861	53,861	53,861	53,861
8	Tax exempt (for NEW CIP and R&R)	28,041	30,550	33,040	35,506	37,940	40,338	42,692	44,997	47,244	49,427
	Total Debt Service	81,902	84,411	86,901	89,366	91,801	94,199	96,553	98,857	101,105	103,288
9, 10	**Net Income ($000)**	171,411	193,153	201,254	209,769	218,716	228,117	261,611	271,778	282,447	293,639
	Average Rates ($/kWh)	0.1311	0.1239	0.1269	0.1299	0.1330	0.1362	0.1309	0.1341	0.1375	0.1410
	Average Rates [Breakeven] ($/kWh)	0.1029	0.0921	0.0940	0.0960	0.0980	0.1000	0.0895	0.0915	0.0937	0.0958
	Percent Rate Savings	21.55%	25.65%	25.87%	26.10%	26.34%	26.58%	31.64%	31.76%	31.89%	32.03%

1 Rates reflect CPUC Final Decision # 03-12-035 issued 12/18/03 in PG&E Bankruptcy case.
2 Rates reflect predominance of primary & secondary service customers
3 Adjusted for Direct Access Load
4 Includes Customer Service, Lost Franchise Fees, Property Taxes, and A&G.
5 25% @ PG&E Medium Commercial Rate - Margin averages $0.02 / kWh due to assumption that 25 % of municipal load is sold at PG&E rates.
6 Principle include System Purchase, Acquisition Cost, Severance, Financed Reserves.
7 Interest rate @ 6.25% 30 year debt level service
8 Interest rate @ 5.00%, 30 year level debt service assuming 100% of capital additions financed annually.
9 Assuming PG&E rates
10 Available to fund CIP, R&R, to reduce rates, to build reserves, or to transfer to general fund.

Worst Case / Scenario 2

Note	Item	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	CUSTOMERS/LOAD										
	Load (MWh)										
	Residential	1,336,077	1,336,077	1,336,077	1,336,077	1,336,077	1,336,077	1,336,077	1,336,077	1,336,077	1,336,077
	Commercial										
	Small	527,393	527,393	527,393	527,393	527,393	527,393	527,393	527,393	527,393	527,393
	Medium	1,462,059	1,462,059	1,462,059	1,462,059	1,462,059	1,462,059	1,462,059	1,462,059	1,462,059	1,462,059
	Large	1,138,644	1,138,644	1,138,644	1,138,644	1,138,644	1,138,644	1,138,644	1,138,644	1,138,644	1,138,644
	Municipal	609,130	609,130	609,130	609,130	609,130	609,130	609,130	609,130	609,130	609,130
	Total Load at Meter	5,073,304	5,073,304	5,073,304	5,073,304	5,073,304	5,073,304	5,073,304	5,073,304	5,073,304	5,073,304
	Less Direct Access	507,076	507,076	507,076	507,076	507,076	507,076	507,076	507,076	507,076	507,076
	Load Served (MWh)	4,566,228	4,566,228	4,566,228	4,566,228	4,566,228	4,566,228	4,566,228	4,566,228	4,566,228	4,566,228
	Losses @8.0% (MWh)	365,298	365,298	365,298	365,298	365,298	365,298	365,298	365,298	365,298	365,298
	Energy Requirement	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526
	Market purchases	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526
	PRICES										
	Market Electricity ($/MWh)	$ 36.00	$ 41.60	$ 38.72	$ 40.82	$ 44.49	$ 47.54	$ 49.68	$ 52.57	$ 54.83	$ 58.03
	DWR Bond Repayment ($/MWh)	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 27.00	$ 13.50	$ 13.50
	Distribution O&M ($/MWh)	$ 6.07	$ 6.07	$ 6.07	$ 6.21	$ 6.36	$ 6.52	$ 6.67	$ 6.83	$ 7.00	$ 7.18
	Transmission ($/MWh)	$ 5.40	$ 6.24	$ 5.81	$ 6.12	$ 6.67	$ 7.13	$ 7.45	$ 7.89	$ 8.22	$ 8.71
1	Rates ($/kWh)										
	Residential	$ 0.1336	$ 0.1257	$ 0.1248	$ 0.1268	$ 0.1290	$ 0.1312	$ 0.1244	$ 0.1268	$ 0.1215	$ 0.1244
2	Commercial / Industrial										
	Small	$ 0.1811	$ 0.1703	$ 0.1695	$ 0.1726	$ 0.1759	$ 0.1792	$ 0.1728	$ 0.1764	$ 0.1724	$ 0.1765
	Medium	$ 0.1470	$ 0.1383	$ 0.1374	$ 0.1398	$ 0.1422	$ 0.1447	$ 0.1444	$ 0.1471	$ 0.1422	$ 0.1454
	Large	$ 0.1366	$ 0.1285	$ 0.1277	$ 0.1297	$ 0.1320	$ 0.1342	$ 0.1364	$ 0.1389	$ 0.1337	$ 0.1366
	Direct Access Average Credit ($/MWh)	$ 37.35	$ 42.72	$ 39.96	$ 41.97	$ 45.49	$ 48.41	$ 50.46	$ 53.23	$ 53.97	$ 57.04
3	**REVENUES ($000)**										
	Residential	$ 178,500	$ 167,960	$ 166,778	$ 169,472	$ 172,372	$ 175,275	$ 166,257	$ 169,388	$ 162,388	$ 166,152
	Commercial / Industrial										
	Small	95,511	89,797	89,413	91,043	92,767	94,506	91,133	93,017	90,918	93,084
	Medium	214,923	202,174	200,945	204,336	207,962	211,604	211,138	215,071	207,931	212,582
	Large	155,539	146,344	145,348	147,722	150,272	152,827	155,367	158,124	152,249	155,549
	Direct Access	(18,939)	(21,662)	(20,262)	(21,282)	(23,065)	(24,546)	(25,588)	(26,993)	(27,368)	(28,924)
	Total Revenues	$ 625,533	$ 584,613	$ 582,222	$ 591,291	$ 600,307	$ 609,666	$ 598,307	$ 608,607	$ 586,118	$ 598,443
	EXPENSES ($000)										
	Power Supply (@market prices)	172,107	198,897	185,127	195,162	212,703	227,268	237,522	251,347	262,137	277,443
	Public Purpose Programs	18,367	17,279	17,171	17,458	17,766	18,075	17,781	18,115	17,484	17,880
	DWR Energy/Bond Costs	129,080	129,080	129,080	129,080	129,080	129,080	129,080	129,080	64,540	64,540
	Nuclear Decomissioning	1,811	1,811	1,811	1,811	1,811	1,811	1,811	1,811	1,811	1,811
	Post transition period CTC	44,642	44,642	44,642	44,642	44,642	44,642	44,642	44,642	44,642	44,642
	FTA	22,971	22,971	22,971	22,971	22,971	22,971	-	-	-	-
	Operations and Maintenance	30,788	30,788	30,788	31,527	32,284	33,058	33,852	34,664	35,531	36,419
	Transmission ISO (TAC, GMT, Congestion / Ancil	25,816	29,834	27,769	29,274	31,905	34,090	35,628	37,702	39,321	41,616
4	Other Operations Cost	28,684	28,684	28,684	29,373	30,078	30,800	31,539	32,296	33,103	33,931
	Direct Access	(18,939)	(21,662)	(20,262)	(21,282)	(23,065)	(24,546)	(25,588)	(26,993)	(27,368)	(28,924)
	Total Expenses	$ 455,328	$ 482,325	$ 467,781	$ 480,016	$ 500,175	$ 517,250	$ 506,266	$ 522,663	$ 471,201	$ 489,359
	Net Revenues ($000)	$ 170,205	$ 102,288	$ 114,441	$ 111,275	$ 100,132	$ 92,416	$ 92,040	$ 85,944	$ 114,917	$ 109,084
5	**Municipal Margin**	$ 12,183	$ 12,183	$ 12,183	$ 12,183	$ 12,183	$ 12,183	$ 12,183	$ 12,183	$ 12,183	$ 12,183
	DEBT SERVICE ($000)										
6, 7	Federally Taxable (Principal: 1520000000	$ 116,586	$ 116,586	$ 116,586	$ 116,586	$ 116,586	$ 116,586	$ 116,586	$ 116,586	$ 116,586	$ 116,586
8	Tax exempt (for NEW CIP and R&R)	$ 2,543	$ 5,048	$ 7,511	$ 9,991	$ 12,483	$ 14,986	$ 17,494	$ 20,005	$ 22,516	$ 25,023
	Total Debt Service	$ 119,129	$ 121,634	$ 124,098	$ 126,577	$ 129,070	$ 131,572	$ 134,080	$ 136,591	$ 139,102	$ 141,610
9, 10	**Net Income ($000)**	$ 63,259	$ (7,163)	$ 2,526	$ (3,120)	$ (16,755)	$ (26,974)	$ (29,857)	$ (38,465)	$ (12,002)	$ (20,342)
	NPV @ 6.0%	($179,035)									
	Assumed Debt ($000)	$ 1,562,759									
	Average Rates ($/kWh)	$ 0.1401	$ 0.1310	$ 0.1304	$ 0.1325	$ 0.1345	$ 0.1366	$ 0.1340	$ 0.1363	$ 0.1313	$ 0.1341
	Average Rate	$0.1333									
	Average Rates [Breakeven] ($/kWh)	$ 0.1287	$ 0,1353	$ 0,1326	$ 0.1359	$ 0.1410	$ 0.1453	$ 0.1434	$ 0.1477	$ 0.1367	$ 0.1413
	Average Breakeven Rate	$0.1405									
	Percent Rate Savings	8.17%	-3.31%	-1.66%	-2.59%	-4.82%	-6.42%	-7.03%	-8.32%	-4.13%	-5.43%
		-5.52%									

Note	Item	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	CUSTOMERS/LOAD										
	Load (MWh)										
	Residential	1,336,077	1,336,077	1,336,077	1,336,077	1,336,077	1,336,077	1,336,077	1,336,077	1,336,077	1,336,077
	Commercial										
	Small	527,393	527,393	527,393	527,393	527,393	527,393	527,393	527,393	527,393	527,393
	Medium	1,462,059	1,462,059	1,462,059	1,462,059	1,462,059	1,462,059	1,462,059	1,462,059	1,462,059	1,462,059
	Large	1,138,644	1,138,644	1,138,644	1,138,644	1,138,644	1,138,644	1,138,644	1,138,644	1,138,644	1,138,644
	Municipal	609,130	609,130	609,130	609,130	609,130	609,130	609,130	609,130	609,130	609,130
	Total Load at Meter	5,073,304	5,073,304	5,073,304	5,073,304	5,073,304	5,073,304	5,073,304	5,073,304	5,073,304	5,073,304
	Less Direct Access	507,076	507,076	507,076	507,076	507,076	507,076	507,076	507,076	507,076	507,076
	Load Served (MWh)	4,566,228	4,566,228	4,566,228	4,566,228	4,566,228	4,566,228	4,566,228	4,566,228	4,566,228	4,566,228
	Losses @8.0% (MWh)	365,298	365,298	365,298	365,298	365,298	365,298	365,298	365,298	365,298	365,298
	Energy Requirement	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526
	Market purchases	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526	4,931,526
	PRICES										
	Market Electricity ($/MWh)	$ 60.82	$ 62.40	$ 64.02	$ 65.69	$ 67.40	$ 69.15	$ 70.95	$ 72.79	$ 74.68	$ 76.63
	DWR Bond Repayment ($/MWh)	$ 13.50	$ 6.75	$ 6.75	$ 6.75	$ 6.75	$ 6.75	$ -	$ -	$ -	$ -
	Distribution O&M ($/MWh)	$ 7.36	$ 7.54	$ 7.73	$ 7.92	$ 8.12	$ 8.32	$ 8.53	$ 8.75	$ 8.97	$ 9.19
	Transmission ($/MWh)	$ 9.12	$ 9.36	$ 9.60	$ 9.85	$ 10.11	$ 10.37	$ 10.64	$ 10.92	$ 11.20	$ 11.49
1	Rates ($/kWh)										
	Residential	$ 0.1221	$ 0.1146	$ 0.1175	$ 0.1204	$ 0.1234	$ 0.1265	$ 0.1209	$ 0.1240	$ 0.1272	$ 0.1305
2	Commercial / Industrial										
	Small	$ 0.1734	$ 0.1673	$ 0.1715	$ 0.1757	$ 0.1801	$ 0.1846	$ 0.1805	$ 0.1852	$ 0.1899	$ 0.1948
	Medium	$ 0.1426	$ 0.1356	$ 0.1388	$ 0.1421	$ 0.1455	$ 0.1489	$ 0.1438	$ 0.1474	$ 0.1510	$ 0.1548
	Large	$ 0.1339	$ 0.1266	$ 0.1295	$ 0.1325	$ 0.1356	$ 0.1387	$ 0.1333	$ 0.1365	$ 0.1398	$ 0.1432
	Direct Access Average Credit ($/MWh)	$ 59.71	$ 60.51	$ 62.07	$ 63.66	$ 65.30	$ 66.98	$ 67.99	$ 69.76	$ 71.57	$ 73.43
3	**REVENUES ($000)**										
	Residential	$ 163,097	$ 153,181	$ 156,978	$ 160,871	$ 164,861	$ 168,952	$ 161,517	$ 165,707	$ 170,004	$ 174,408
	Commercial / Industrial										
	Small	91,449	88,221	90,424	92,682	94,997	97,370	95,212	97,663	100,176	102,751
	Medium	208,533	198,219	202,924	207,748	212,694	217,763	210,234	215,443	220,784	226,258
	Large	152,479	144,122	147,454	150,870	154,371	157,961	151,730	155,411	159,184	163,051
	Direct Access	(30,278)	(30,685)	(31,474)	(32,283)	(33,113)	(33,964)	(34,477)	(35,373)	(36,293)	(37,236)
	Total Revenues	$ 585,280	$ 553,058	$ 566,307	$ 579,888	$ 593,811	$ 608,083	$ 584,217	$ 598,852	$ 613,854	$ 629,232
	EXPENSES ($000)										
	Power Supply (@market prices)	290,768	298,328	306,085	314,043	322,208	330,585	339,181	347,999	357,047	366,331
	Public Purpose Programs	17,543	16,637	17,037	17,447	17,867	18,298	17,633	18,075	18,529	18,994
	DWR Energy/Bond Costs	64,540	32,270	32,270	32,270	32,270	32,270	-	-	-	-
	Nuclear Decomissioning	1,811	906	906	906	906	906	-	-	-	-
	Post transition period CTC	44,642	22,321	22,321	22,321	22,321	22,321	-	-	-	-
	FTA	-	-	-	-	-	-	-	-	-	-
	Operations and Maintenance	37,330	38,263	39,219	40,200	41,205	42,235	43,291	44,373	45,482	46,619
	Transmission ISO (TAC, GMT, Congestion / Ancil	43,615	44,749	45,913	47,106	48,331	49,588	50,877	52,200	53,557	54,950
4	Other Operations Cost	34,779	35,649	36,540	37,453	38,390	39,349	40,333	41,341	42,375	43,434
	Direct Access	(30,278)	(30,685)	(31,474)	(32,283)	(33,113)	(33,964)	(34,477)	(35,373)	(36,293)	(37,236)
	Total Expenses	$ 504,750	$ 458,436	$ 468,816	$ 479,463	$ 490,385	$ 501,588	$ 456,838	$ 468,616	$ 480,698	$ 493,092
	Net Revenues ($000)	$ 80,529	$ 94,621	$ 97,491	$ 100,425	$ 103,426	$ 106,495	$ 127,379	$ 130,236	$ 133,156	$ 136,141
5	**Municipal Margin**	$ 12,183	$ 12,183	$ 12,183	$ 12,183	$ 12,183	$ 12,183	$ 12,183	$ 12,183	$ 12,183	$ 12,183
	DEBT SERVICE ($000)										
6, 7	Federally Taxable (Principal: 1520000000	$ 116,586	$ 116,586	$ 116,586	$ 116,586	$ 116,586	$ 116,586	$ 116,586	$ 116,586	$ 116,586	$ 116,586
8	Tax exempt (for NEW CIP and R&R)	$ 27,523	$ 30,008	$ 32,475	$ 34,918	$ 37,331	$ 39,707	$ 42,040	$ 44,324	$ 46,552	$ 48,717
	Total Debt Service	$ 144,109	$ 146,595	$ 149,062	$ 151,504	$ 153,917	$ 156,293	$ 158,627	$ 160,911	$ 163,138	$ 165,303
9, 10	**Net Income ($000)**	$ (51,397)	$ (39,791)	$ (39,388)	$ (38,896)	$ (38,308)	$ (37,615)	$ (19,065)	$ (18,492)	$ (17,800)	$ (16,980)
	Average Rates ($/kWh)	$ 0.1311	$ 0.1239	$ 0.1269	$ 0.1299	$ 0.1330	$ 0.1362	$ 0.1309	$ 0.1341	$ 0.1375	$ 0.1410
	Average Rates [Breakeven] ($/kWh)	$ 0.1453	$ 0.1355	$ 0.1384	$ 0.1413	$ 0.1443	$ 0.1474	$ 0.1379	$ 0.1410	$ 0.1442	$ 0,1475
	Percent Rate Savings	-10.86%	-9.40%	-9.11%	-8.81%	-8.50%	-8.19%	-5.35%	-5.12%	-4.88%	-4.63%

1 Rates reflect CPUC Final Decision # 03-12-035 Issued 12/18/03 in PG&E Bankruptcy case.
2 Rates reflect predominance of primary & secondary service customers
3 Adjusted for Direct Access Load
4 Includes Customer Service, Lost Franchise Fees, Property Taxes, and A&G.
5 25% @ PG&E Medium Commercial Rate - Margin averages $0.02 / kWh due to assumption that 25 % of municipal load is sold at PG&E rates.
6 Principle include System Purchase, Acquisition Cost, Severance, Financed Reserves.
7 Interest rate @ 6.25% 30 year debt level service
8 Interest rate @ 5.00%, 30 year level debt service assuming 100% of capital additions financed annually.
9 Assuming PG&E rates
10 Available to fund CIP, R&R, to reduce rates, to build reserves, or to transfer to general fund.